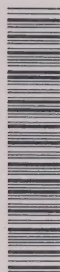


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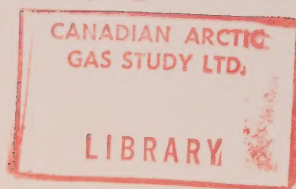


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MACKENZIE DELTA GAS DEVELOPMENT SYSTEM

VOLUME 2

WELL DESIGN AND OPERATIONS



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MACKENZIE DELTA GAS DEVELOPMENT SYSTEM

VOL. 2

WELL DESIGN AND OPERATION

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I. SUMMARY

Production wells in arctic regions are faced with problems not encountered in other producing areas of the world. These problems arise from the need to suspend and produce wells through thick permafrost intervals. This section of the application deals with the Applicants' assessment of these problems and subsequent design methods and procedures. It also considers potential well-design problems not unique to the arctic.

To date, the most serious problem with wells drilled and completed through permafrost intervals has been casing collapse caused by internal freezeback which has occurred during well suspension or extended shut-in periods. The collapse results from the freezing of water-based fluids in the annuli of the well extending through the permafrost. To complete wells through permafrost intervals safely, these freezable fluids must be removed from the well before suspension or extended shut-ins.

Freezeback of the permafrost can also generate very high pressures around a wellbore. There are no known documented cases of casing failure from this condition (external freezeback), but field tests conducted at Prudhoe Bay Field, Alaska and in the Mackenzie Delta have indicated that the pressure generated by refreezing around the wellbore can be abnormally high. Consequently, the external casing strings set through these intervals must be designed to withstand such freezeback pressures.

A study of the effects of producing hot fluids for extended periods through permafrost indicates that under some conditions thermal disturbance can result in subsidence of the permafrost. This settlement of the soil around the wellbore can result in frictional downdrag forces on the adjacent casing string, which, if extreme, could cause casing failure. At present the problem of thaw subsidence and subsequent casing

downdrag is only hypothetical, as actual production experience in arctic wells is not extensive enough to have confirmed its existence. However, mechanisms have been suggested that make thaw subsidence likely under some conditions. Assessment of this problem indicates that thermal insulation will probably be needed to limit the amount of thermal disturbance around the wellbore and minimize the downdrag loads. Worst-case mathematical models indicate that, in an adequately insulated well, the casing design shown in Figure 1 can accommodate the maximum downdrag loads well enough to limit the thaw radius around the well to less than 10 feet.

Another potential problem resulting from thermal disturbance around the wellbore is decomposition of gas hydrates contained in hydrated gas reservoirs. The gas liberated as a result of heat input from hot produced fluids can cause a pressure buildup on adjacent casing strings if this gas is contained within the reservoir-casing system. Pressures could be generated until the formation or casing yields to relieve them. Alternatively, with a poor cement job the gas can channel to the surface and create a containment problem. Consequently, casing strings must be designed to withstand the formation fracture pressure so that the formation yields instead of the casing, and provision may have to be made for venting the gas to surface.

The problems associated with producing high-volume wells through thick permafrost, the design requirements worked out from studying these problems, and the resultant design methods and procedures, are summarized in Table I. A schematic of a possible Mackenzie Delta well design is shown in Figure 1. The casing design and general well configuration in Figure 1 is based on anticipated requirements for typical Mackenzie Delta development wells, and is presented to demonstrate design features that will fulfill the basic requirements for wells completed through permafrost.

The selection of well equipment and methods or procedures can vary considerably, depending on specific conditions.

Other Mackenzie Delta well-design considerations are summarized in Table II. As in Table I, basic design requirements are presented and methods and procedures are outlined. Potential problems not unique to the arctic that must be considered in the well design and operation include: 1) sand control, 2) hydrate control during well start-up, and 3) corrosion control. If these problems are encountered in a particular area or field in the Mackenzie Delta, remedial or preventative techniques commonly used in other producing areas will be applied.

Other well-design and operation considerations presented in Table II include: 1) safety systems (surface and subsurface safety valves), 2) monitoring, 3) production parameters, and 4) contingency plans. Design considerations for water-disposal, condensate-injection and observation wells are also outlined.

The application also contains a section on anticipated drilling activities for Mackenzie Delta development wells.

A detailed description and assessment of each of the design considerations summarized in Tables I and II is presented in the sections of the application that follow.

II. PROBLEMS UNIQUE TO THE ARCTIC

A. EXTERNAL FREEZEBACK

1. Description

Drilling and producing of arctic wells, insulated or uninsulated, will result in thawing of the permafrost around the wellbore. When these wells are shut in after completion, or production is interrupted for several months, the soil and water surrounding the outer casing string will freeze. The phase-change expansion on freezing of pore water and free water, drained from thawing soil and/or introduced by drilling fluids, will cause a buildup of pressure on the casing and permafrost.

Pressure buildup on the casing depends on the mechanical behaviour of the frozen soil. Ice and permafrost deform at pressures substantially higher than overburden pressures, thus imposing an equivalent pressure gradient on the surface casing. The surface casing must therefore be designed to resist the pressures generated by this action.

2. Assessment

Information on maximum freezeback pressures has been obtained from field tests and model studies.

a) Field Tests

Freezeback pressures were measured at a Prudhoe Bay test site in a well drilled on a water-base mud.^{1,2} The maximum freezeback pressures measured at the test site can be represented over the interval from surface to 800 feet by the equation:

$$p = 1.44 Z + 130$$

where p = maximum freezeback pressure in psi

Z = depth from surface in feet

Below 800 feet the freezeback pressure gradient reverted to the lateral overburden gradient for Prudhoe Bay of 0.65 psi per foot. A maximum freezeback pressure of 1400 psi was recorded at 1046 feet, which was the deepest transducer location. Extrapolation of these data indicates a maximum freezeback pressure of about 2100 psi at the base of 2000 feet of permafrost.

In the Mackenzie Delta, freezeback pressures were measured at the Atertak E-41 location. The data listed below indicate a maximum freezeback pressure gradient of 1.1 psi per foot for the depth range 500-1000 feet.

<u>Transducer Depth Feet</u>	<u>Maximum Freezeback Pressure (psi)</u>
520	551
550	628
614	701
645	647
985	1096

b) Theoretical Models

Models based on the thermal and mechanical behaviour of permafrost have been developed to calculate external freezeback pressures.^{1,2} The freezeback pressures calculated for the Prudhoe Bay test site are in good agreement with the rate of buildup and magnitude of the measured pressures. The rate of freezeback was obtained by thermal simulation, and pressure response was calculated by assuming Coulomb yield behaviour at depths shallower than 800 feet and elastic behaviour below this depth.

The maximum freezeback pressures initially measured at the Prudhoe Bay wellsite were the result of freezing a relatively small thaw zone. Models predict that the maximum freezeback pressure for a thaw

radius greater than two feet is essentially independent of thaw radius.¹ This prediction was confirmed by the fact that the maximum pressures recorded during two freezeback cycles of different thaw radius at the Prudhoe Bay test site were nearly the same.¹

3. Design Requirements and Procedures

Surface casing strings must be designed to withstand the stresses imposed on the casing during freezeback. The collapse rating of the surface casing must be higher than the maximum freezeback pressures calculated from the formulas described above.

On this basis, 13-3/8 inch 72 lb/ft N-80 surface casing can safely withstand the maximum pressures generated by freezeback in 2000 feet of permafrost. At 2000 feet maximum freezeback pressures are predicted to be about 2100 psi - considerably less than the collapse rating for this casing, which is 2670 psi plus the internal hydrostatic pressure.

4. References

1. Goodman, M.A. and Wood, D.B., 1973, A mechanical model for permafrost freezeback pressure behaviour: Soc. Petroleum Engineers, Paper 4589.
2. Perkins, T.K., Rochan, J.A. and Knowles, C.R., 1973, Studies of pressures generated upon refreezing of thawed permafrost around a wellbore: Soc. Petroleum Engineers, Paper 4588.

B. INTERNAL FREEZEBACK

1. Description

Internal freezeback and resultant tubular damage is caused by the freezing and expansion of trapped, water-based, casing-to-casing annular fluids. A well completed through permafrost is vulnerable to this condition during suspension after drilling activity or during extended shut-in periods. If these inactive periods are long enough, the heat stored in the surrounding permafrost from drilling or producing operations will dissipate, resulting in temperatures that could fall below the freezing point for the particular fluid in the well annulus. All the casing failures (collapse) through permafrost intervals reported in both North Slope and Mackenzie Delta wells have been attributed to internal freezeback.

2. Assessment

Numerous instances of casing failure resulting from internal freezeback have been reported in North Slope wells.^{1,2,3} These failures were caused by the freezing of fluids left between strings of casings, but to avoid leaving freezable fluids in the annuli is not simple. Some wells at Prudhoe Bay, Alaska and in the Mackenzie Delta have suffered casing collapse even when special efforts had been made to place non-freezing fluids in the casing-to-casing annuli. For example, there have been collapses where cement was left between casing strings, the idea being to replace the liquids in these annuli with a solid freeze-resistant cement sheath. Such failures are generally attributed to inefficient displacement of drilling fluids and/or overwatered cement which allowed water pockets to form and then freeze. In the case of another reported collapse, where oil mud had been circulated in the annulus, inefficient displacement of drilling fluids was blamed for the failure.

These instances of casing failure caused by internal freeze-back in early arctic wells serve to point out the severity of the problem and the need to take extreme care in placing nonfreezable fluids in casing annuli through permafrost. Prudhoe Bay operators now adhere to this practice, and British Petroleum, Alaska is reported to swab the vulnerable annuli dry and subsequently fill them with oil as a permanent completion fluid.

3. Design Requirements

To prevent problems from internal freezeback, freezable fluids must be effectively removed from susceptible annuli before a well vulnerable to freezeback conditions is left. Consequently, this premise leads to the following basic design requirements for arctic wells:

a) Provide a means of readily placing nonfreezable fluids in permanent casing-to-casing annuli through permafrost intervals.

b) Provide for a compatible nonfreezing completion fluid through permafrost intervals. The main criteria for selecting a fluid to leave in the annulus of a well completed through permafrost are:

i) It must not freeze when exposed to *in situ* permafrost temperatures.

ii) It must protect the well against corrosion.

iii) It must not segregate, allow suspended solids to settle or cause precipitates to form.

iv) It must not create significant mixing, handling or pollution problems.

v) It must be able to be weighted as required to provide well control.

vi) It must provide good thermal insulating characteristics.

vii) It must be economical and readily available.

As no fluid completely satisfies all the above requirements, it is not practical to select any one fluid for use in all arctic completions. Table III lists several nonfreezable fluids which have possible application as completion fluids for arctic wells. Their pertinent properties are noted in the table, with remarks on usage.

c) In view of the problems encountered in early arctic wells with overwatered cement slurries and subsequent freezing and casing damage, casing-to-casing annuli through permafrost intervals should not be cemented unless absolutely necessary.

4. Design Methods and Procedure

A means of replacing freezable annular fluids with suitable nonfreezing fluids can be provided as follows:

a) Provide a circulating device, such as a sliding sleeve or a stage cementer, in the inner casing string for effective displacement of residual drilling fluids. Displacement can be either by circulation or by a swab-and-fill technique.

b) Use a hanger-tieback arrangement such that the inner casing string through the permafrost can be retrieved during vulnerable freezback periods. After retrieval of the tieback strings, the wellbore through the permafrost can be displaced to a nonfreezing fluid. This method has the distinct advantage of eliminating the annulus of concern.

The well sketch of Figure 1 shows these two systems as they might be used in typical Mackenzie Delta well completion.

As noted under design requirements, it would not be practical to select any one nonfreezable completion fluid for general arctic application. The fluids noted in Table III constitute a base group from which nonfreezing completion fluids may be selected for particular applications.

5. References

- 1 Bleakley, W.B., 1971, North Slope operators tackle production problems: Oil Gas J., Oct. 25.
- 2 _____, 1973, How BP Alaska cements through permafrost: Petroleum Engineer, April.
- 3 Koch, R.D., 1973, Problems of drilling onshore: Proc., Fifth Intern. Cong., Arctic oil and gas - problems and possibilities, May.

C. THAW SUBSIDENCE

1. Description

The depth of permafrost in the Mackenzie Delta area varies from a few feet to over two thousand. Production of warm reservoir fluids will cause the permafrost to thaw around the wellbore. When the permafrost thaws, it can undergo from insignificant to quite large amounts of deformation, depending on permafrost conditions. There can be a deformation related to volume change when the ice becomes water, and there may also be a later, time-dependent deformation if the soil is weakened and settles under the overburden load. The total soil movement, therefore, depends mainly on the ice content and the initial state of stress in the permafrost. Downward movement of the thawed soil will impose frictional downdrag loads on the well casing. Since the casing is secured rigidly below the permafrost and perhaps also at the surface, this downdrag action can create axial stresses, compressive at the base and tensile at the surface, if the casing is fixed there as well. Under some soil conditions and model concepts, tensile stresses are predicted at the base of the permafrost.

Mathematical model analyses and practical field tests have been conducted to evaluate thaw subsidence and predict the distribution and amount of compressive and tensile downdrag loading on the surface casing over the producing life of a well. The size and distribution of downdrag loads will be related to the depth of permafrost, the lithology, the ice content and stress conditions of the permafrost, the radius of thaw, the method of completion, the friction coefficient and the drainage characteristics of the thawed material.

2. Assessment

Thaw subsidence can generally be attributed to one or more of the following permafrost conditions and associated mechanisms:

a) The soil may contain segregated ice. The presence of excess ice at depth is an obvious cause of subsidence after thaw. The possibility of ice lenses having formed under large overburden pressures has been investigated both experimentally and theoretically by several authors.^{1,2} Ice-lens formation is a function of soil type, mineral content of the interstitial water, and the availability of water. The general consensus is that few or no ice lenses should exist in clean sands below 50 feet, and in silts below 100 to 200 feet.^{1,2} In clays, ice-lensing is almost solely a function of temperature and can occur under large overburden pressures.¹

In the Mackenzie Delta, visual examination of about 5000 shot-hole logs indicated that, in the 264 holes which penetrated massive ice, the ice occurred most frequently at a depth of 40 feet. In 53 holes, ice was reported at depths of 100 to 150 feet.³ Shell conducted a shallow coring program to 450 feet at the Kumak C-58 site, and did not encounter any ice lenses below 50 feet. A gravilog survey of the permafrost section in the Taglu D-55 well showed no massive ice sections below 160 feet (no readings were taken above 160 feet). At a test site at Prudhoe Bay, no ice lenses or any forms of massive excess ice were found in the permafrost, and no lenses or massive ice forms were detected below about 50 feet in the photographs of the walls of air-drilled holes.⁴

On the basis of experimental and field information, it is concluded that thick ice lenses are not likely to occur below 50 feet in the Mackenzie Delta. Thawing of near-surface ice lenses will contribute appreciably to surface subsidence but will not create excessive downdrag forces.

b) The soil when frozen may have been underconsolidated with respect to the present overburden. In the initial frozen state, the soil is not in complete grain-to-grain contact and, on thawing, will consolidate because of the loss of support previously provided by pore ice and the gradual transfer of load to the soil grains. Typical soils movement by this process can be quite large and the soil can fail progressively, undergo grain rearrangement and settle to equilibrium under the overburden load. However, since unconsolidated soils lack competence, it is unlikely that the soil movement will be transmitted directly to the casing and slip will probably occur. The rate of consolidation will depend on the compressibility of the soil and its permeability.

c) The soil may be normally consolidated, with the interstitial ice carrying a small fraction of the effective overburden. If the soil contains zones of low permeability or the water supply is inadequate, the void caused by the phase change of ice to water may not be completely filled, thus causing a reduction in pore pressure. The net result is an almost instantaneous decrease in the volume of the soil, with a subsequent increase in intergranular stress. Permafrost strains caused by pore-pressure reduction are an order of magnitude lower than those due to consolidation, and are not likely to cause local soil failure. However, the smaller elastic strains in more competent soil may be directly transmitted to the casing.

Two general approaches to modelling the subsidence of thawed permafrost have been pursued:

First, there is a soil-mechanics approach that involves the coupling of existing arching and thaw-consolidation theories.^{5,6,7} It is called the "thaw-consolidation analysis", and has been developed by Imperial in consultation with Dr. N. R. Morgenstern of the University of Alberta and Dr. J. F. Nixon of R. M. Hardy and Associates Ltd. in Calgary. The analysis is

considered conservative in that the soil movement after thaw is assumed to be enough to cause the soil to fail, when its full shear-failure resistance is applied to the casing as a distributed axial load. The relevant arching-equilibrium and consolidation equations are solved in concert by means of a finite-difference computer program, which also computes the casing-stress distribution.

For the proposed Taglu completion scheme with thermocase insulation, and with the casing restrained at surface by 60 feet of refrigeration, a worstcase analysis with this model predicts that the maximum casing stress (at the permafrost base) will not exceed 50,000 psi. The safety factor for N-80 grade pipe is thus at least 1.6. This analysis assumes that we can restrict the twenty-year radial thaw to less than 10 feet on average. Our thermal-simulation study indicates that we can do better. On the other hand, if casing insulation is not run, the thaw-consolidation analysis predicts that prohibitively high casing stresses may be generated.

The second basic approach to modelling subsidence is to treat the permafrost as an elastic medium and use a finite-element computer program to solve the soil deformations. This procedure is called the "poro-elasticity analysis" and assumes that the soil is relatively competent, so that elastic strains are induced in the permafrost when the pore pressure is reduced by ice melting (i.e., pore-pressure reduction mechanism).⁴

From what are considered to be reasonably conservative assumptions, the poro-elasticity model predicts casing stresses less than 40,000 psi for an insulated Taglu gas well. For an uninsulated Taglu well it predicts higher casing stresses, which will exceed 40,000 psi but should be less than 80,000 psi. In other words, we again have confirmation that acceptable safety factors may not be guaranteed unless insulation is used.

A thaw-subsidence field test was conducted by BP at Prudhoe Bay.^{4,8} From the results they concluded that, with the thaw radius reached during the test (estimated at 10 to 12 feet), there was no evidence of any casing damage.

3. Design Requirements and Procedures

This review of mathematical models, simulations and thaw-subsidence test data indicates, to date, that casing stresses caused by subsidence with insulated, surface-restrained completions will not be excessive. A maximum stress range of 50,000 psi is calculated by Imperial's thaw-consolidation model for a well with 2,000 feet of permafrost. This figure represents a design safety factor of at least 1.6 for N-80 casing with respect to thaw-subsidence loads plus dead weight.

The surface-casing design adopted to date calls for 13-3/8" N-80 pipe, with minimum yield strength of 80,000 psi and full joint strength.

It should be noted that in areas where competent permafrost is known to exist, there will be no settlement of the permafrost on thawing, and thermal insulation will not necessarily be required.

4. References

1. Hoekstra, P., 1969, Water movement and freezing pressures: Proc., Soil Sci. Soc. America, V. 33.
2. Williams, P.J., 1967, Properties and behavior of freezing soils: Norwegian Goetech. Inst. Pub. 72, NRC 9854.
3. Rampton, V.N. and MacKay, J.R., 1971, Massive ice and icy sediments throughout the Tuktoyaktuk Peninsula, Richards Island and nearby areas, District of Mackenzie: Geol. Surv. Canada, Paper 71-21.
4. Smith, R.E. and Clegg, M., 1970, Analysis and design of production wells through thick permafrost: Proc. 8th World Petroleum Cong. 3, 379.

5. Terzaghi, K., 1943, Theoretical soil mechanics: New York, Wiley, 66.
6. Morgenstern, N.R. and Nixon, J.F., 1971, One-dimensional consolidation of thawing soils: Can. Geotech, J., 8 (4) 558.
7. Nixon, J.F., and Morgenstern, N.R., 1973, Practical extensions to a theory of consolidation of thawing soils: Proc. 2nd Intern. Conf. Permafrost, Yakutsk.
8. Davies, B.E. and Borman, R.D., 1973, Field investigation of effect of thawing permafrost around wellbores at Prudhoe Bay: Soc. Petroleum Engineers, 48th Ann. Fall Mtg., Las Vegas, Nev. (Sept.), Paper 4591.

D. HYDRATED GAS RESERVOIRS

1. Description

There is considerable evidence to suggest that reservoirs containing solid gas-hydrates exist in some areas of the Mackenzie Delta. Physical conditions for hydrate stability are well defined, and in portions of the Delta these stable conditions extend to depths as great as 3,500 feet.^{1,2}

In Mackenzie Delta exploration programs, the producers have obtained data which suggest that gas hydrates are present below the permafrost in some areas, and hydrate zones have been tentatively identified in three wells at depths between 2,500 and 3,500 feet. In each well, distribution of these zones combined with available gas analyses and subsurface temperature and pressure data indicates that gas hydrates could be stable at the depths where they are suspected to occur. The zones were characterized by: 1) strong gas shows while drilling, 2) a zero spontaneous-potential log response, 3) high electrical resistivity, 4) high sonic velocities, and 5) gas leakage after cementing shallow casing in some instances. (In general, it is not possible to identify gas hydrates within permafrost intervals by electric-log response, since the pore ice can give a response similar to that of hydrates.)

The potential problems with hydrated gas reservoirs, as regards well design and operation, result from thermal disturbance of the hydrates zones by heat from drilling, cementing and producing operations. Heat input into these zones can cause hydrates to decompose, and the liberated gas can either build up pressures if contained or cause channeling problems if free to expand.

2. Assessment

Gas liberated as a result of heat input into gas-hydrate zones during drilling, cementing and producing operations can cause the following problems during these operations (drilling and cementing operations are included because they significantly affect well design):

a) Drilling Problems

Strong gas shows during drilling through suspected hydrate zones are a sign of liberated gas due to the heat input of the drilling mud or to hydrates in the drill cuttings decomposing as they are circulated to surface. Normally, the amount of liberated gas results in only low concentrations in the mud stream and no particular drilling problem is incurred. However, checks must be made to insure that the mud system does not become excessively gas-cut. Moreover, it is desirable to set casing as soon as practical after drilling through a gas-hydrate zone.

b) Cementing Problems

The heat liberated by the setting of cement can cause gas hydrates to decompose. If the hydrate zone has a negligible permeability (as is expected when solid hydrates occupy the pore spaces), the liberated gas can flow into the cement column to cause gas-cutting and subsequent poor cement jobs.

c) Producing Problems

The decomposition of gas hydrates caused by heat input from produced fluids could result in two problems:

i) If the hydrate zone is contained - i.e., impermeable zones above and below, and a good cement job precluding leakage into the casing-hole annulus - the decomposition of hydrates can cause a pressure buildup until the formation yields to relieve the induced pressure. In

this event, casing strings set through hydrate zones must have a collapse strength high enough to withstand formation-failure pressure. Formation-breakdown pressure gradients are normally less than 1.0 psi/foot.

ii) If the hydrate zone is not contained by a good cement job, the liberated gas from hydrate decomposition could, in the extreme, channel to the surface and cause containment problems. The risk of gas channelling to the surface should not be serious if the gas can be contained within casing-to-casing annuli and subsequently vented and disposed of at the surface.

The volumes of gas liberated as a result of producing through hydrate zones will be small. For example, wellbore thermal simulators indicate that radial "thaw" over an extended producing life (twenty years) can spread to about 50 feet from the wellbore. If a zone of this radius is assumed to be 50 feet thick and have a porosity of 30 per cent with the pores completely filled with solid hydrates, the total gas in place in the thaw zone is only about 20 MMSCF. The volumes of gas concerned, therefore, are relatively small for the length of time involved, and are not expected to present any particular problems.

3. Operating and Design Requirements

To circumvent or minimize the potential problems when gas-hydrate zones are present, the following procedures are observed for Mackenzie Delta wells:

a) Drill suspected gas-hydrate zones with mud temperatures as cool as practical, to minimize thermal disturbance. Solid gas-hydrates, like ice, have a latent heat capacity and, in most cases, the temperature of the hydrate zone has cooled to below the stability temperature of the hydrate compound. It will thus take a specific amount of heat energy to

bring the hydrate to its melting temperature, after which the required latent heat must be supplied to decompose the compound. Therefore, with the mud temperature kept to a practical minimum, thermal disturbance and subsequent hydrate decomposition will be almost if not completely eliminated. The optimum drilling-mud temperature (or temperature range) is a subject of current research effort.

b) Set casing through hydrate intervals as soon as practical after drilling through them. This will isolate the zone(s) from the drilling-fluids system while deeper and hotter zones are being drilled, and eliminate the influx of decomposed-hydrate gas into the mud system.

c) To cement casing strings set through hydrate zones, use cool cement slurries with a low heat of hydration. Again, these procedures are designed to cause the least possible thermal disturbance of the hydrate zone and thus make for a better cement job.

d) Design casing strings set through hydrate zones to withstand the breakdown pressure of the formation. A 1.0 psi/foot collapse pressure gradient will be used for casing design until field tests determine the actual breakdown pressure of the hydrate formations.

e) Provide a means of safely venting gas from casing annuli at the wellhead in the event that gas volumes from decomposing gas hydrates cannot be contained underground. Vented relief valves installed at the wellhead will provide an automatic backup or safety system should hydrate or other gas not be contained down hole. Severe gas channelling to the surface would require remedial action to cut off the migration.

4. References

1. Katz *et al.*, 1959, Handbook of Natural Gas Engineering: New York, McGraw-Hill Book Co., Inc.
2. Katz, D.L., 1971, Depths to which frozen gas fields (gas hydrates) may be expected: J. Petroleum Technology, April.

hydrate formation in the well tubulars or surface equipment causes a decrease in production with an increase in bottom-hole pressure. While both types of hydrate formation cause operating problems, tubing freeze-off is the most difficult to overcome. In the Delta area this problem is compounded by a permafrost zone as deep as 2000 feet.

Mathematical models are available to establish bounds for this problem. Plots of both pressure and temperature versus depth can be generated for specified flowing conditions. It is possible with this type of model to determine the pressure and temperature conditions of a gas at any point within the well. By comparing these data with standard gas-hydrate envelopes, critical hydrate conditions in the well system can be predicted as a function of time.

2. Assessment

Hydrate control becomes critical on initial well startup and during periods of well testing to evaluate the formation. It is essential that drawdown be controlled so that pressure and temperature conditions of the flowing gas are within the solid-hydrate zone for as short a period as possible. Each differing situation must be analyzed so that a family of curves (wellhead temperature vs. time) can be developed to describe the anticipated well flowing conditions completely. It will then be possible to determine the requirements that must be incorporated into the over-all well design to accommodate the severity of a particular hydrate problem.

a) Reservoir-Face Hydrate Formation

This condition may occur in areas where the reservoir temperature only slightly exceeds the hydrate equilibrium temperature. In such cases a slight pressure drawdown could cause enough temperature drop for solid gas-hydrates to form at the wellbore. Formations with these particular

characteristics will present production problems. Drawdown will have to be kept within well-defined limits to prevent production impairment.

b) Uphole Hydrate Formation

Hydrates can form in the tubing, with the problem being more severe near the surface. The causes are gas cooling by heat transfer to the formation, and gas expansion as the gas moves from bottom hole to surface. Having formed, these hydrates are particularly difficult to remove. Once a hydrate forms within the permafrost zone, it is stable and will not decompose naturally; the plug must therefore be removed by some mechanical method. To date, the only effective way to remove an established hydrate plug is to use snubbing equipment and a macaroni string, circulate either hot diesel or methanol on top of the plug, and gradually work through it. While the method is effective, it is expensive and cumbersome. In development wells the problem must be avoided by prudent selection of tubing size or by the use of inhibitors or heat strings.

3. Design Requirements

Wells must be produced so that pressure drawdowns are maintained at levels to prevent hydrate formation at the sandface, while bottom-hole temperatures are kept high enough (with artificial heat if necessary) to prevent hydrates from forming in the upper portion of the wellbore. To accomplish this the following requirements will have to be met:

a) Well drawdown must be controlled in order to keep sandface temperature drops within acceptable limits. Large pressure drops might result in conditions of temperature and pressure that allow the solid gas-hydrates to form (Figure 4).

b) Additional pressure losses in vertical flow, as well as heat transfer from the flowing stream, will determine the severity of

hydrate conditions in the flow stream. Computer programs are available to model this situation during transient and steady-state conditions. These analyses suggest that the following criteria for well design must be met:

i) Tubular goods must be of a size that will minimize restrictions and at the same time allow for enough gas velocity to produce any liquids present.

ii) Under some conditions, circulating strings can be installed to a depth sufficient to cover critical areas. Either a parallel or a concentric heat-string system may be needed. It must allow for circulation of a hot fluid and create a positive heat exchange with the flowing gas.

iii) Where flowing conditions are not normally within the hydrate-formation zone, it may be necessary to install some type of mandrel in the tubing to allow for fluid injection. This could be required during well startup should conditions pass through the hydrate region while the well is approaching its flowing equilibrium temperature.

B. CORROSION CONTROL AND MATERIAL SPECIFICATIONS

1. Corrosion Control

a) Drilling

During the drilling operation, maintaining a pH value in the drilling fluid between 10 and 12 has proved to be an effective corrosion-control measure for steel drill pipe. Corrosion control has been and would continue to be monitored at some rigs by corrosion rings in the drill string. In addition, the drill string would be inspected periodically; if corrosion rates proved high, an oxygen scavenger (sodium sulphite) would be added.

b) Completion

The exact requirements for corrosion protection of casing in contact with arctic soils have not been established. Steps to minimize the corrosion potential of packer fluids may be taken at the completion stage. However, laboratory data collected over two years on typical drilling fluids used in the arctic indicate the corrosion rates to be low, significantly less than 1 mil per year. Also, an inhibited or noncorrosive fluid would be placed in the tubing/casing and/or casing/casing annulus to minimize any risk of corrosion.

At this time cathodic protection of casing is not considered necessary for arctic conditions. If required, such protection can be applied in permafrost.

c) Production

During production of some gas wells, corrosion of tubing and wellhead equipment from the combination of CO₂ and water has been recognized as a possible problem. The conventional method of handling tubing corrosion has been to add corrosion inhibitors. This practice has been successful

and would probably be applied to these wells. However, the use of alternative tubing metallurgy or internal coatings will be considered.

Wellhead components such as valves, chokes, and swages can be subject to erosion-corrosion in the presence of CO₂ and water if the flow velocities are excessive. If design requirements expose these wellhead components to critical velocities, measures such as metal-plating, hard-surfacing or coating of the components will be specified to overcome the erosion-corrosion effects, with the help of inhibition.

The corrosion-control measures outlined above would be monitored. Corrosion coupons, electrical resistance probes, X-rays, ultrasonics, tubing inspection techniques, and iron counts of the produced water have been traditional monitoring tools that have a history of success and would be used in varying combinations on arctic wells.

2. Material Specifications

The hardware now used in arctic wells has been developed from materials used in other Canadian oil and gas fields, with some modifications for the slightly lower temperatures. Both users and suppliers have developed materials that are safe to use at -60°F. Casing and tubing that meets API specifications has been used successfully and would be used further, with some selection exercised as to grade and method of manufacture to ensure adequate toughness properties for low-temperature handling. The metallurgy of wellhead equipment exposed to the extremes of the arctic environment has received special consideration, to ensure that the low-temperature properties are adequate. The latest edition of API specifications 6A has been adhered to, supplemented where necessary by final user specifications. This approach has provided safe and workable equipment and would be continued during the development stage.

C. SAND CONTROL

Programs are now under way to evaluate potential sand-control problems in Mackenzie Delta production wells. The main objective of these programs is to define the sand-control measures needed for producing wells before development activities. An early indication of potential sand problems will allow the producers to assess different sand-control techniques and to determine the best method(s) to apply in Mackenzie Delta wells if they are needed.

1. Defining Potential Sand-Control Problems

The ability to predict the need for sand control is extremely important in production operations. In deciding on the method of well completion, the higher risk of well-component replacement without sand control must be weighed against the cost and production impairment inherent in various control techniques. For high-rate gas wells it is particularly important to define the sand-control requirements early, as sand entrained in the high-velocity gas can severely erode downhole and surface equipment.

To define sand-control requirements for producing wells in the Mackenzie Delta, the operators are:

a) Analyzing the strength characteristics of sandstone core materials that are suspected to be weak and might fail under producing conditions. The results of these laboratory analyses are: i) compared with similar measurements from Gulf Coast sands where the failure characteristics are well known, and ii) used to provide a basis for theoretical sand-failure predictions. The comparison with Gulf Coast rock provides a qualitative means of assessing potentially weak sands, while the theoretical approach attempts to predict the critical flow rate or pressure

drawdown for sand failure by considering the state of stress near the well and the rock-strength parameters.

b) Using sand-monitoring techniques during production testing of wells, and planning to implement similar measures during future production testing, with special concern for the shallow tertiary sand intervals. Sand monitors (erosion or sonic type) are designed to determine if sand was produced during the flow period. They provide important information as to whether the formation failed during the test, which, coupled with the pressure drawdown and rate information obtained from the flow test, can provide valuable data on the critical pressure and rate conditions at which the formation failed. It is anticipated that such results can be used to validate the theoretical sand-failure techniques mentioned above. To date, sand monitors (expendable erosion type) have been installed during production tests on two Taglu wells, neither of which registered any sand production.

c) Noting sand produced on drillstem tests of exploration wells. If there is no sand failure, information on rock strength is provided, since a range of pressure drawdown conditions can be derived from the pressure data.

d) Attempting to relate rock-strength parameters and, subsequently, sand-failure tendencies to well-log parameters. Some successful efforts of this kind have been reported in other producing areas,¹ but the technique has not been validated under Mackenzie Delta conditions. Information provided by the core analyses and test data will help provide this validation.

It is expected that these evaluation techniques will permit an early definition of potential sand-control problems.

2. Sand-Control Techniques

If the evaluation program establishes that sand-control measures are needed to produce a particular Mackenzie Delta reservoir safely, it is anticipated that methods proved in other areas - particularly the Gulf Coast - could be effective. These methods include gravel packing, plastic consolidations, and various other chemical processes. The best technique will depend on the particular application and can be determined only when all pertinent data are available.

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IV. OPERATIONS

A. SAFETY SYSTEMS

Each producing gas well would be equipped with remotely controlled surface and subsurface safety-valve systems. Each system would be designed to "fail safe", and besides providing manual and remote shut-in capabilities, would perform automatic shut-ins for a variety of emergency conditions. Sensing elements provided in these systems include pressure, liquid level, flow rate, and temperature, all of which can activate shut-in and alarm components. Figure 5 shows a typical layout for surface and subsurface safety-valve systems.

In addition to the remotely controlled surface and subsurface safety valves, the tubing-to-casing annuli would be equipped with pressure-relief systems as a protection against overpressuring. The annuli could also be equipped with pressure sensors that will activate alarms for early warning of pressure buildup.

1. Surface Safety Valves (SSV)

Remotely controlled surface safety valves are operated by a control system through monitors normally placed at points in the flowline and in the surface facilities. The valve is equipped with an operator, which may be pneumatic, electric, hydraulic or a combination of these. Any malfunction is sensed by monitoring pilots, which cause the control to bleed pressure from the valve operator so that the valve closes, usually by spring force. Normally, the entire control and operating systems become inoperable until a manual startup procedure is initiated. The valve is "fail safe" in that the spring force holds it in the normally closed (NC) position unless control-line pressure is applied to open it. An added

safety factor is provided by fusible plugs installed in the control line for fire protection.

2. Subsurface Safety Valves (SSSV)

The subsurface safety valves would be remotely controlled at the surface through a hydraulic control system. The SSSV's are maintained in the open position by hydraulic pressure transmitted through control lines from a surface control unit. Any interruption in the control-line pressure will relieve the opening force at the valve. Consequently, like the SSV, the SSSV system is designed to be "fail safe". It provides automatic shut-in of the well for emergencies and can be activated manually. The hydraulic control system uses monitors or other controls designed to sense high or low pressure, high temperature, etc., and to shut in the well in the event of an emergency.

The SSSV's would be set below the base of the permafrost, to provide a positive means of shutting in a well that has suffered unforeseen damage through permafrost-associated problems such as freezeback or subsidence.

3. Annulus Pressure-Control Systems

Casing-to-casing and tubing-to-casing annuli would be protected from overpressuring by suitable pressure-relief systems. Depending on the particular application, the system can be a rupture disc, a relief valve, back-pressure valves, or a combination of these. It is designed to protect the well tubulars from pressures outside accepted design and operating limits. It is likely that pressure sensors would also be installed in the annuli, to activate an alarm if pressure builds up above a preset level.

Periodically, the well-safety and pressure-relief systems would be activated to make sure that they were in good order. Regular inspections and preventive maintenance programs would also be set up to insure the greatest reliability for the systems at all times.

B. WELL MONITORING

The performance and status of all operating facilities would be monitored at a central facility called the Operations Centre located at the gas plant. The main computer system and master control unit would be in the Operations Centre and would link all components of the production system. Remote terminal units would be located at each well cluster to relay various signals to the master control unit. These signals would include system status, alarm conditions, and measurement and control functions, and would be available continuously or on request. The following would be monitored:

1. Safety Valves

The status of the following safety valves would be monitored periodically:

a) Subsurface Safety Valve (SSSV)

This valve could be actuated manually from surface or automatically in the event of some abnormal or emergency condition. It would be a fail-safe type valve (*see* Sec. IV.A.2).

b) Wellhead Safety Valve (SSV)

This valve would be actuated automatically in the event of an abnormal or emergency condition; it could also be activated manually or remotely (*see* Sec. IV.A.1).

2. Alarms

a) Sand Probes

Probes would be monitored and an alarm issued should erosion in surface facilities reach critical levels.

b) Fire

As part of cluster safety, a fire-alarm system would be installed; it would also incorporate the wellhead.

3. Production Parameters

Several parameters would be monitored periodically at or near the wellhead and the data relayed to the control centre. Alarms would be included for abnormal fluctuations. The production parameters would include:

- a) Flowing temperature
- b) Flowing pressure
- c) Flow rate
- d) Annuli pressures
- e) Chemical injection rates

C. CONTINGENCY OPERATIONS

Mackenzie Delta gas wells would be equipped with the most up-to-date well-control and safety systems during both drilling and producing operations. Drilling crews and operating personnel would be thoroughly trained in all areas of contingency operations. With these precautions, a blowout, serious spill, or release of hydrocarbons to the surroundings would be most unlikely. Nevertheless, contingency plans would be in effect to cover all conceivable emergencies, thereby minimizing the impact of any failure of well or wellsite systems.

1. Drilling Operations

Well-control procedures during drilling operations are discussed in detail in Section V.B.6.

2. Producing Operations

The producing wells would be equipped with both surface and subsurface "fail safe" safety valves. These valves would be designed to shut in the wells for specified emergency conditions (*see* Sec. IV.A.), such as fire, flowline rupture, or any other condition where it is considered necessary to have the well(s) shut in until the problem has been remedied. Such safety valves are designed to respond automatically to emergency conditions and can also be operated manually at the central control centres or at the wellsites. Hence, for any failure of surface equipment, the well(s) can be shut in both at the surface and below the base of the permafrost, to prevent the effects from spreading. In addition, subsurface problems that could endanger the integrity of a well, such as casing failure or tubing leaks, can actuate the safety valves. It should be noted that well parameters would be monitored both by the computerized

production-control system and manually, so that subsurface problems in the wells would probably be detected early and appropriate remedial action taken before an emergency developed.

3. Blowouts

Although all conceivable precautions would be taken to insure complete control of drilling and producing wells at all times, it is recognized that the mechanical control/safety systems and the personnel that operate them are not 100 per cent infallible, and that a blowout *could* occur under extreme circumstances.

Should control of a well be lost, blowout contingency operations would be in effect. An example of the decision-making process for control problems with a drilling well is presented in Section V.B.6. Although this plan is outlined for a drilling well, it would also apply to a wild production well. In brief, all possible action would be taken to bring a blowout under control fast. A last resort would be to drill a relief well and kill the wild well in the subsurface. In an emergency as extreme as a blowout, protection of human life would be the first consideration. Measures would be taken to protect property and the environment in accordance with established spill contingency plans.

V. OTHER CONSIDERATIONS

A. DISPOSAL AND OBSERVATION WELLS

Conditioning raw gas to meet pipeline specifications requires the removal of water and, with few exceptions, of heavy hydrocarbons. The water would be injected into an underground formation, and any liquid hydrocarbons would similarly be injected until a market was found for the product.

About 15 to 20 per cent additional wells would be drilled to provide spare productive capacity to be used as required. When not producing, these wells could serve as observation wells.

1. Disposal Wells

The quantities of water and liquid hydrocarbons to be disposed of at each gas-processing plant are estimated at about 500 barrels per day and 7000 barrels per day respectively. Where convenient, the disposal wells would be located close to the plant to reduce water-freezing problems. The water would be injected to an aquifer associated with the producing zones, or to some other acceptable water sand. Injectivity tests would be needed to determine if the receiving formation could accept the quantities of disposal water at the required rates. It would also be necessary to test the compatibility of the formation water in the injection zone and the water from the gas plant, which might originally have come from several different formations.

It is planned to inject liquid hydrocarbons into the producing formation. These liquids could be re-produced when a market becomes available.

The quantities of injection liquids would allow both streams to be injected into one well with a dual-completion arrangement. A dual completion with two small tubing strings (2-3/8 and 3-1/2 inch, for example), with appropriate packer arrangement, would be satisfactory. Alternatively, a tubing-casing system could be used, with one fluid being injected down the tubing and the other being moved through the tubing-casing annulus. In either case packers would be used to isolate the formation intervals that the injected fluids were entering.

A thermal and downdrag analysis would be made when disposal quantities and conditions were sufficiently defined. The result would determine whether insulation should be installed across the permafrost interval of the disposal wells. Provision would be made to displace water from the injection line and the tubing interval across the permafrost and replace it with a nonfreezing fluid during shut-in periods.

The disposal well would be equipped with safety valves and alarm systems as described for the producing wells, and well conditions would be monitored regularly.

2. Observation Wells

Reservoir pressure would have to be measured periodically to monitor the reservoir performance of the producing gas pools. The procedure is to shut in all producing wells and observe the pressure buildup, or shut in each well alternately and obtain the static reservoir pressure in the drainage area of that well. Pressure data can also be obtained from observation wells through periodic pressure surveys. Since these wells would be potential producers, they would be completed in the same manner as producing wells except that insulation across the permafrost section

and refrigeration of the near surface would not be needed while they were being used as pressure observation wells. They would be equipped with safety valves the same as the producing wells. Tubing and annular pressures and temperatures would be monitored regularly.

These observation wells would be installed in accordance with the following criteria: 1. The wells would be installed in the oil-bearing zone of the reservoir. 2. The wells would be installed in the oil-bearing zone of the reservoir. 3. The wells would be installed in the oil-bearing zone of the reservoir. 4. The wells would be installed in the oil-bearing zone of the reservoir. 5. The wells would be installed in the oil-bearing zone of the reservoir. 6. The wells would be installed in the oil-bearing zone of the reservoir. 7. The wells would be installed in the oil-bearing zone of the reservoir. 8. The wells would be installed in the oil-bearing zone of the reservoir. 9. The wells would be installed in the oil-bearing zone of the reservoir. 10. The wells would be installed in the oil-bearing zone of the reservoir.

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Well No.	Well Name	Well Type	Well Status
1.	Well No. 1	Oil	Producing
2.	Well No. 2	Oil	Producing
3.	Well No. 3	Oil	Producing
4.	Well No. 4	Oil	Producing
5.	Well No. 5	Oil	Producing
6.	Well No. 6	Oil	Producing
7.	Well No. 7	Oil	Producing
8.	Well No. 8	Oil	Producing
9.	Well No. 9	Oil	Producing
10.	Well No. 10	Oil	Producing

B. DRILLING OPERATIONS

Drilling operations in the Mackenzie Delta pose unique problems. Considerable research effort, and experience gained over the past several years, have resulted in the development of new techniques to cope with these problems. These techniques would be utilized in development drilling operations. This section summarizes the anticipated drilling activities for Mackenzie Delta development wells. It is included in the application 1) because of the direct relation between drilling operations and well design, and 2) as support for other sections of the application, especially the environmental considerations.

The problems encountered in the Mackenzie Delta area during drilling operations are summarized below, with the present solutions.

	<u>Problem</u>	<u>Solution</u>
1.	Extreme cold.	Fully winterized, adequately heated drilling rigs. Adequate metallurgical properties of all materials exposed to cold temperatures.
2.	Stabilizing the top layer of permafrost.	Adequate rig foundation. Refrigerated and insulated conductor pipe.
3.	Washouts in massive gravel and sand beds within permafrost zone.	Cool Bentonite-Polymer KCL drilling fluid.
4.	Hydrated gas zones.	Cool drilling fluid.
5.	Cementing in permafrost zone.	Gypsum based, freezing-point depressed, cement blend.
6.	Shallow hydrocarbons.	Adequate well-control equipment and crew training.
7.	Abnormally pressured formation.	Early detection of transition zones and casing set in proper pore pressure for well control.
8.	Waste disposal.	Generating minimum volumes.

1. Drilling Equipment

Arctic drilling rigs are basically the same as those used in southern operations. Some important special features would be:

- a) High substructures (approximately 30 feet) to accommodate the sophisticated well-control equipment.
- b) Extensive housing and heating system, to cope with extremely low temperatures and high winds.
- c) A layer of insulating material (gravel, artificial insulation or piles) underneath the entire rig substructure, to minimize thermal disturbance of the upper permafrost layer.
- d) Insulated and refrigerated conductor pipe, to stabilize upper permafrost layer.
- e) Insulating material or piles under stockpiled supplies.
- f) A sophisticated surface mud-handling system, to control the amount of solids in the drilling fluid.
- g) A high degree of automation and instrumentation, with emphasis on well control and detection of abnormally pressured formations.
- h) Most drilling fluid and cementing materials handled in bulk.
- i) Waste-disposal methods that safeguard the environment.

2. Drilling Fluids

Selection and close control of drilling fluids would play a major role in combating several of the drilling problems encountered in the Mackenzie Delta.

a) Surface Hole

Conventional water-base drilling fluids as used in the western provinces of Canada have generally proved inadequate for drilling through and below thick permafrost sections in the Mackenzie Delta. Problems of hole fill, stuck pipe, washed-out section and mechanical failure of mud-handling equipment were commonly reported by the operators. Air^{1,2,3}, foam^{4,5}, chilled diesel⁶, and refrigerated water-base muds^{2,7,8} have been used with varying degrees of success. Often, drilling methods that work in one area cannot be used in another because of the permafrost's varying thickness, lithology and physical characteristics.

The drilling fluid currently used by Imperial, Shell and Gulf on surface holes is a water-base system containing Bentonite-Polymer and KCl. The system is characterized by:⁹

- i) High yield point, which results in efficient sand and gravel removal at low annular velocities.
- ii) Ease of mixing in the field.
- iii) Flexibility of rheological properties.
- iv) Depressed freezing point.
- v) Compatibility with Ca^{++} ions.
- vi) Acceptable corrosion rates at high pH.

This fluid has been highly successful in drilling surface holes in the Mackenzie Delta region, and it is anticipated it would be used in development drilling operations.

b) Intermediate Hole

A water-based bentonite drilling fluid would very likely be used on the intermediate hole. To minimize pollution hazards, no toxic components would be added to the drilling fluid where nontoxic alternative materials were feasible. An adequate solids-control system would be used to minimize solid wastes. When abnormally pressured formations were encountered, the density of the mud would be increased by adding weight material. A typical mud-system composition is given below:

<u>Component</u>	<u>Quantity (#/bbl)</u>	
	<u>Surface Hole</u> <u>(0-3000'+)</u>	<u>Main Hole</u> <u>(3000'+)</u>
Bentonite	10	10-20
Potassium Chloride	10-40	As required for hole stability
Caustic Soda (pH Control)	0-1/3	1/4-1/3
Polymer	1/2	1/2
Lignosulfonate	0-2/3	1-10
Barites	(As required to control formation pressure)	
Sodium Acid Pyrophosphate	-	1/2
Sodium Bicarbonate	0-1/3	1

c) Disposal of Waste Fluids

Efforts would be made to minimize volumes of liquid effluents throughout drilling operations. Use of mechanical mud disposing and handling systems would allow drilling fluids to be reclaimed and used again in subsequent holes where feasible. Only cuttings and mud contaminated by excess fines and/or cement would need to be disposed of into the central sump or settling pit. Nevertheless, minimum sump capacity anticipated at this time is 10,000 bbls/well for an average 10,000-foot well.

Additional wastes that could be generated during the drilling and completion operation are contaminated diesel oil, oily wastes and spent-acid water. These would be diverted to the sump for natural separation, and hydrocarbons would be skimmed off and incinerated. Solids in mud and cuttings would be allowed to settle out, with the liquid phase being either treated and reclaimed, or disposed of by freezing in the sump. Placing borrow material and 4 to 5 feet of gravel on top could convert the sump area into usable pad working surface.

d) Special Conditions

The above comments on mud systems apply as long as mechanical problems are not encountered during drilling and completion procedures. Should problems occur, such as lost circulation, differential sticking, and side-tracking, additional mud additives might be required, such as diesel oil, oil-base lubricants, sawdust or wood fibres, and other specialty products. The quantities of these products needed would be relatively small, and ultimate disposal by incineration or storage in the central sump would present no further difficulty.

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3. Refrigerated and Insulated Conductor Pipe

In some areas of the Mackenzie Delta, the near-surface permafrost is ice-rich and its thawing results in soil settlement. To prevent thawing of the near surface in exploration wells, a 60-foot refrigerated and insulated conductor pipe would be installed before the start of drilling operations. Although the design may vary somewhat, the pipe is constructed basically as shown in Figure 6.

Such a conductor pipe has effectively stabilized the top permafrost layer and maintained a rigid foundation for the drilling-rig substructure. A refrigerated and insulated conductor pipe would probably be used in development drilling.

4. Drilling Gas Hydrates

Natural gas may exist in hydrate form in subsurface reservoirs if conditions are conducive to hydrate formation.^{1,2,3,4,5,6} Such conditions are likely in arctic regions, where the temperature is low enough for hydrates to form both in the permafrost and in a substantial layer immediately below it. Shallow-gas indications from mud logs in regions of continuous permafrost should, therefore, be considered as potential hydrate zones.

For control of gas hydrates during drilling, the following procedure is suggested:

a) If and when the depth of permafrost is established (crystal-cable survey or other indicators) at a location in the arctic, plot this depth on a 32°F isotherm (Fig. 7). Plot a geothermal gradient of 1.6°F/100 feet (approximate for Mackenzie Delta area) from the base of permafrost and establish the potential hydrate zone for methane (encountered in most cases) and 0.6 gravity gas. For example, with 1000 feet of permafrost the gas-hydrate zones can extend to 1850 feet for methane and 3100 feet for 0.6 gravity gas (Fig. 7).

b) If gas is encountered in subsequent drilling operations in a potential hydrate-forming zone:

i) Check for the flow - if there is very little or none, it is highly probable that hydrocarbons encountered are hydrated gas.

ii) Attempt to contain gas hydrates in a "frozen" state by keeping the temperature of the circulating mud as low as practical. In most cases, circulating-mud temperatures of 45° to 50° will be low enough to keep hydrates frozen.

iii) Very little can be gained by weighting up the mud, as tremendous pressures are needed to keep hydrates frozen if warm (60°F) mud is used.

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5. Arctic Cementing Practices

Cementing surface casing through permafrost presents some unusual problems and has been the subject of considerable research. For a satisfactory cement job, the cement must set, develop sufficient compressive strength, and form an adequate bond with the permafrost formation, under conditions where the subsurface temperatures may be below freezing to a depth of 2000 feet or more.

The problems of cementing casing in permafrost were first investigated in the early 1950's in connection with drilling operations in the U.S. Naval Reserve 4 in Northern Alaska.^{1,2} It was reported then that conventional oilwell cements did not set at subfreezing temperatures and that very little hydration took place below 40°F. Consequently, the temperature of conventional cement must be kept above 40°F to ensure a satisfactory set in permafrost. Another solution to the low-temperature problem is to use cement blends specially formulated to set in cold environments.^{3,4,5,6,7} Special blends are available for cementing through permafrost; these are generally referred to as high-alumina cements (Fondue-cements) and gypsum-based, freezing-point depressed blends, which are also referred to as gypsum-cement blends.

High-alumina cements have a rapid hydration rate, and the heat evolved is enough to sustain the setting reaction in permafrost. This rapid heat evolution can be detrimental in the high-ice-content or ice-consolidated permafrost zones. The blend sets and gains strength rapidly, reaching about 95 per cent of the ultimate strength in twenty-four hours.⁶ However, when exposed to thaw-freezing cycles (simulated producing-well conditions), high-alumina cements are susceptible to degradation and retrogression of compressive strength.^{6,7} This degradation is apparently caused by a change

from a metastable crystalline structure to a more stable form, and is accompanied by a colour change from near-black to reddish brown.^{6,8} High-alumina cements bond adequately to a low-ice-content frozen formation⁵, and set at subfreezing temperatures. These blends have been used to cement through the permafrost zones.

Freezing-point depressed, gypsum-cement blends set and rapidly develop adequate compressive strength at subfreezing temperatures.^{3,6,7,10,11,12} No loss of compressive strength was reported on exposure to thaw-freezing cycles.⁷ Since the cement properties are adequate at cold temperatures, gypsum-cement blends are most commonly used for cementing through the permafrost both in Canada and on the Alaskan North Slope.

Information from laboratory and field testing to date indicates the following:

a) Gypsum-based, freezing-point depressed cement blends should be used to cement conductor and all casing strings through the permafrost zone.

b) Slurry temperatures of gypsum-based, freezing-point depressed blends should be kept between 35°F and 40°F. The attached diagram (Fig. 8) should be used when designing slurry for temperature.

c) Since thickening can take place very early if warmer (over 60°F) slurries are used, the slurry temperature of normal gypsum-based, freezing-point depressed blends *should not exceed 55°F*.

d) Gypsum-based, freezing-point depressed slurry tends to entrain some air when mixed in the field, and the *pressurized fluid-density balance* (Tru-Wate Cup) or a continuous densimeter should be used for determining the density of the slurry.

e) Every effort should be made to assure a proper displacement and to avoid excess water in cement slurry (particularly in the perma-

frost zone) and the following recommendations are helpful in this regard:

- i) Move pipe continuously while cementing and displacing.
- ii) Use adequate and controllable surface mixing equipment.
- iii) Monitor the slurry density continuously with the pressurized drilling-fluid balance (or continuous densimeter).
- iv) Monitor the density of cement returns to surface, and use this information as one of the criteria for the quality of the cement job when attempting to cement to surface.

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6. Contingency Plans

The probability of a blowout while drilling production wells in the Mackenzie Delta area is extremely remote. Formation conditions would be known from exploration and delineation wells, and the most up-to-date safety equipment and well-control procedures would be used at all times.

a) Well Control

Well-control procedures would be specifically formulated for each drilling well. Some recommended guidelines developed by industry (Arctic Petroleum Operator's Association) are described in Reference 1.

Crew training is perhaps the most important facet of blowout prevention. Pre-spud meetings would be held, at which all emergency conditions would be discussed and company procedures and policies stated. Also included would be a familiarization session on safety equipment, its use and proper maintenance. All personnel would be thoroughly familiar with standard well-control techniques. Supplementary training for supervisory staff, such as PITS (Petroleum Industry Training Service) Well-Control School and Simulator Well Control, would be included.

While drilling operations proceeded, well-control drills would be held regularly to ensure that all rig crew members were thoroughly versed in emergency conditions. These drills would be timed and results recorded on the daily drill report.

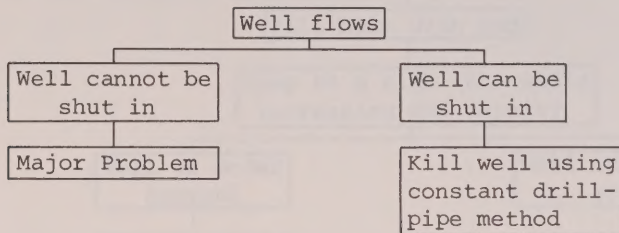
b) Blowout Control

In the event of an influx of formation fluids into the well-bore, there are definite procedures to bring the well under control, whether the problem be minor or extreme. Some examples are given below.

MINOR PROBLEM

A well-control problem is considered to be minor when the inflow of formation fluids is limited and the well can be shut in without fracturing the formation. A decision sequence for such an event is as follows:

Decision Sequence



Corrective Procedure

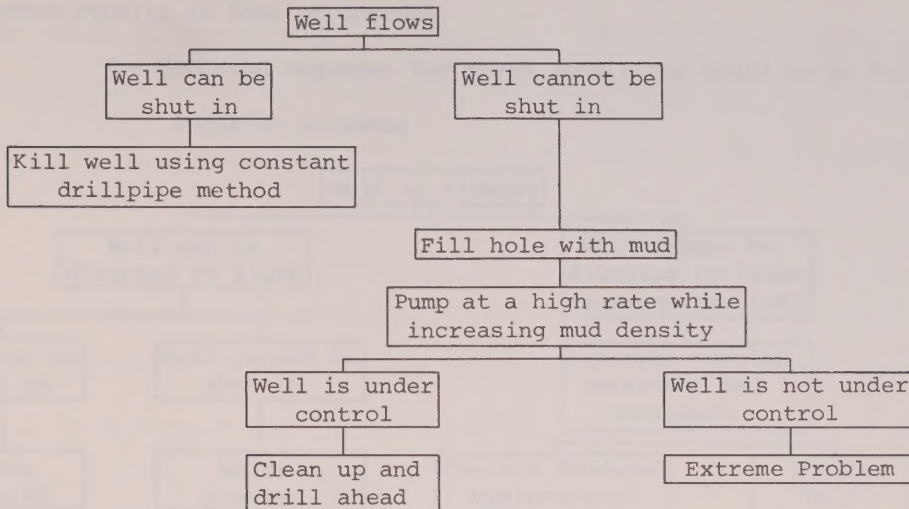
The person responsible at the well site, usually the Tool-pusher/Drilling Supervisor, will:

- i) Kill the well in accordance with the Well Control Procedures. Trained crews will be able to circulate out such kicks routinely by the constant-drillpipe method, and resume drilling operations with a minimum of delay.
- ii) As soon as practicable, advise the Drilling Superintendent or his assistant of the extent of the problem and the control measures taken.
- iii) Prepare a detailed written report of events, procedures used and results obtained.

MAJOR PROBLEM

A major well-control problem occurs when there is a significant influx and the well can be diverted to flare but cannot be shut in without fracturing the formation, and the well can be flared for only a limited time because of the risk of cutting out the surface control equipment. Under these circumstances, the decision sequence could be as follows:

Decision Sequence



Corrective Procedure

i) If the well is brought under control by the circulation of heavier mud, clean up and proceed with the program. The Tool-pusher/Drilling Supervisor will prepare a detailed report of the emergency and the procedures used to overcome it.

ii) If the condition of the well continues to deteriorate, proceed with the operations until the arrival of the people expert in well control. Inform appropriate company and government personnel of the gravity of the problem.

EXTREME PROBLEM

An extreme problem results if:

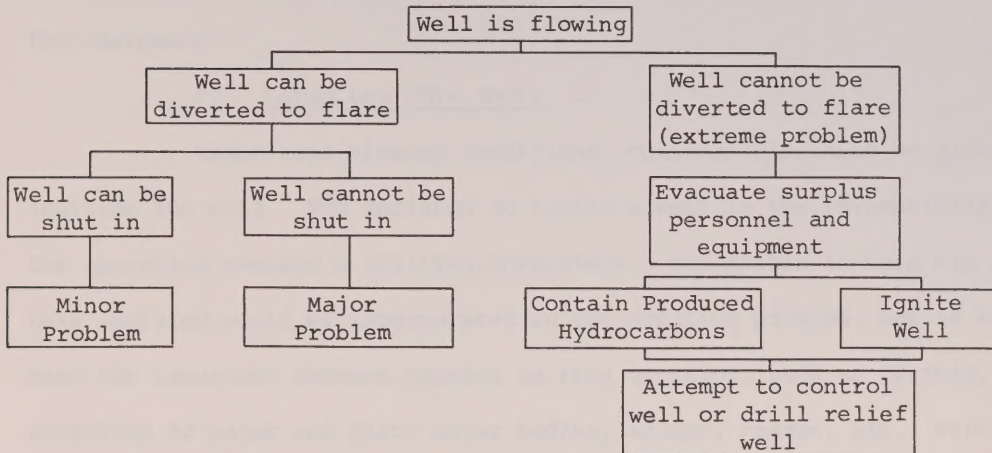
i) An influx cannot be diverted to flare without the resulting back pressure causing the formation to fracture.

ii) The reservoir fluid is in uncontrolled communication with the surface.

iii) Erosional or mechanical failure of the control equipment results in loss of control.

The decision sequence for these conditions could be as follows:

Decision Sequence



Corrective Procedure

i) If the well is brought under control by circulating heavier mud, clean up and proceed with the program. The Toolpusher/Drilling Supervisor will prepare a detailed report of the emergency and the procedures used to overcome it.

ii) If the condition of the well continues to deteriorate, proceed with the operations until the arrival of the people expert in well control. Inform appropriate company and government personnel of the gravity of the problem.

c) Emergency Report Form

In order to permit all groups to perform their respective functions quickly and efficiently under emergency conditions, the information listed in the attached Emergency Report Form (Table IV) must be provided in the first instance in reporting on problems of major or extreme proportions.

This report will normally be prepared by the Toolpusher/ Drilling Supervisor or his delegate and should be as complete and factual as circumstances permit. He will send it to the Drilling Superintendent, and the Drilling Department and senior management will use it to assess the gravity of the situation and formulate preliminary plans to overcome the emergency.

d) Igniting The Well

Under some blowout conditions, consideration must be given to igniting the well. The decision to ignite a well is the responsibility of the operating company's Drilling Supervisor. Guidelines to help him make this decision would be incorporated in the drilling program, and in each case the important factors bearing on this decision, such as terrain, proximity of major and minor water bodies, access, season, etc., would be considered in detail. However, the decision to ignite should be made only as a last resort, and in a situation where it is clear that:

- i) Human life and property are endangered.
- ii) There is no other hope of controlling the situation under the prevailing conditions at the well.

If time permits, an attempt should be made to notify the Drilling Superintendent of the plans to ignite the well. However, the Drilling Supervisor must not delay his decision if human life is threatened.

e) Relief-Well Locations

Detailed photogrammetric surveys would be carried out to locate emergency containment areas adjacent to all arctic development locations, as well as to select the most suitable sites for possible relief wells. Survey plots pinpointing these locations would be attached to the drilling program, in which the following points would be considered in detail:

i) Accessibility of these locations under emergency conditions during both winter and summer.

ii) Methods of providing pads, airstrips, etc., on such locations for the drilling rig, supplies, and support equipment, and the estimated cost of alternative proposals.

iii) The location and availability of the specialized transportation equipment needed to move a rig and supplies onto the relief well during the breakup and summer seasons would be specified where applicable.

iv) The availability in the arctic of air-transportable rigs for drilling relief wells.

v) A tentative program for the relief well, prepared when the drilling program for a particular well was distributed.

vi) Location of the relief well normally as close as possible to the problem well; the exact distance would not be predicted as it would depend mainly on safety considerations (e.g. fluids being produced by the wild well, strength and direction of prevailing winds, etc.), and on the anticipated total well depth.

vii) The total depth of the relief well, which would depend on the depth at which it was desired to intersect the problem well to bring it under control by pumping water, mud or cement.

f) References

1. Arctic Petroleum Operators' Association, 1973, Drilling operations guide: Calgary, Alta., Jan.

7. Abnormal Pressure

By definition, when the drilling-fluid gradient needed to control a well exceeds 0.468 psi/ft. (or 9.0 lbs./gallon), the formation pressure is said to be abnormal. Abnormally pressured formations have been encountered at several localities in the Mackenzie Delta.

It is most important to detect abnormally pressured zones early, then set the intermediate casing string in the proper pore pressure. Several techniques are being used successfully to help detect transition zones:

- 1) Pressure predictions from seismic velocity data give reasonably good correlation, provided good seismic information is available.
- 2) Detection by changes in drilling rates in a continuous lithologic sequence is a very good indicator in the Mackenzie Delta.
- 3) Increased readings from the mud-gas logger are also good indicators.
- 4) Decrease in shale density is a good indicator if shale cuttings are available. As many areas in the Mackenzie Delta contain mudstones rather than shale; mudstones do not provide good cutting samples.
- 5) An increase in the temperature of the circulating drilling fluid is also a good indicator. However, other factors influencing the drilling-fluid temperature must be taken into account.
- 6) An increasing chloride content of the mud sometimes indicates increasing pore pressure.
- 7) There are other changes in mud properties, such as changes in pH of either the fluid itself or its filtrate, or changes in the calcium and sodium ion contents, that can be used for correlation with increasing pore pressure.
- 8) The final confirmation of abnormal pressure can be obtained from the

sonic log. Sonic-log determinations have given good agreement with formation-evaluation pressure data.

Another important consideration for increasing the effectiveness of well-control procedures is the formation-fracture gradient at the casing seat. Many of the critical decisions, such as casing-setting points and alternatives during well-control operations, are based on this value.

An example of procedures for performing such tests is given in Reference 1.

When drilling in areas of abnormal pressures, the following procedures are suggested:

- 1) Establish formation strength (through leak-off test) both at surface and later at intermediate casing seats.
- 2) Monitor several pertinent indicators continuously when approaching the transition zone.
- 3) Set the intermediate casing string in the pore pressure that will allow safe drilling deeper in the hole.

References

1. Arctic Petroleum Operators' Association, 1973, Drilling operations guide: Calgary, Alta., Jan.

8. Directional Drilling

A number of cluster wells would be drilled directionally to reach desired reservoir targets. In some areas deviation angles can reach 60°.

Established directional-drilling practices would be followed. According to some of the Prudhoe Bay operators, directional drillers have to cope with two unique problems:

- a) The presence of permafrost
- b) Occasional erratic magnetic directional-survey results, especially at high latitudes during the intensive solar activities.

To deal with these problems, multishot magnetic directional surveys are taken during the hours of low solar activity (noon). Periodic surveys are also taken with gyroscopes. The wells are usually kicked off after penetrating through the permafrost zone and setting the surface casing.

9. Liquid Storage

a) Fuel Storage and Transportation

The primary fuel source for cluster operation would be diesel oil. It is estimated that fuel stockpiles for approximately 120 days will be needed to last from September 20 (end of barging season) to January 25 (start of trucking season). Permanent storage facilities (1000- to 500-bbl. steel tanks on gravel pads) would be provided, with a capacity of approximately 10,000 barrels per rig. Dykes and firewall systems would be constructed to provide for 100 per cent confinement of total storage volume.

Fuel would be transported by water during the barging season to various staging areas, and from there by vehicle to cluster locations. Aircraft would be used only in emergencies.

Other liquids stored on site would be acid, gasoline and jet fuel. However, the quantities would be small in comparison with the diesel oil, and would add no major problems.

b) Spillage Contingency Plan

All exploratory drilling programs contain a complete section on spill contingency plans. These plans illustrate the procedures to be followed in the event of a spill, and also illuminate any local geographical anomalies. The prominent theme of all arctic contingency plans would be 100 per cent confinement of all spillage. To this end firewalls would be built, and all cluster pads would be graded to drain towards the sump exclusively.

The following plan illustrates a method of spill containment for a single exploratory well. These principles would apply equally to cluster locations.

OIL-SPILL PROCEDURES

All Drilling Supervisors should be thoroughly familiar with the contents of the 'Arctic Division Oil Spill Action Plan for Land-Based Operations in Territorial Areas'. A copy of this manual should always be kept at the wellsite.

The following steps are to be considered as minimum advance preparation for an oil spill, and are the responsibility of the Drilling Supervisor.

- 1) See that all oil-spill equipment is kept in good operating condition. Necessary materials should be on hand and readily accessible.
- 2) Locate all recommended dam, boom, and other control sites. Ensure that they are all easily accessible.
- 3) Cooperate with the Delta Environmental Protection Unit (DEPU) personnel by providing practice sessions with oil skimmer, jet boats, and oil booms.
- 4) Recognize situations where an oil spill could occur and see that proper measures are taken to prevent it.

A basic outline of the steps in controlling an oil spill is as follows:

- 1) Stop the spill at its source.
- 2) Divert or contain the oil already spilled (*see* Fig. 9).
- 3) Alert the Regional Coordinator at Inuvik, briefly describe the spill, and request assistance if necessary. It is the Regional Coordinator's responsibility to notify appropriate government personnel.
- 4) Recover the spilled product.
- 5) Restore the affected area to its original state as nearly as possible.
- 6) Dispose of the recovered product in an approved manner.

WELLSITE CONTAINMENT

Description of Location

This wellsite is a winter location on the flood plain of a channel in the Mackenzie River system. It is 1/3 mile east of the channel. The surrounding terrain is relatively flat with a slight uphill gradient in the easterly direction. There is a small stream half a mile southeast of the location. No clear drainage patterns exist but a general northwesterly flow would be expected.

Minor Spill (low volume)

A low-volume spill will probably be contained in a small area. Snow and low temperatures will restrict flow, and dikes can be built of snow, sawdust boards, or other readily available materials. Manual cleanup with shovels, sorbents and slop containers may be needed.

Major Spill (high volume)

A high-volume spill may reach the river channel, although northwest winds, snow and low temperatures will oppose flow in that direction. Snow dikes with polyethene or bags of sawdust can be used as a main line of defense, but a backup dike system will be needed. Possible control sites are shown in Figure 9. The road to the water supply merits special attention, as flow will be easier down this route. Cleanup operations may require a front-end loader, slop tanks and sorbents.

c) Bulk Storage

Additional lease storage space would have to be allotted for bulk materials. A typical 10,000-foot well uses approximately the following quantities of materials:

Cement	4,000 Sacks
Bentonite	1,500 Sacks
Barytes	5,000 Sacks
Casing	14,000 Feet

Materials would be transported directly to the well-cluster site or to the various staging areas during the barging season.

10. Rig Movement

a) To Cluster Location

It is anticipated that most rigs and support facilities would be barged to within as close a proximity as is feasible to the actual cluster location. Barging operations can be carried out with a reasonable degree of certainty from June 15 until September 20. Rigs can also be transported over channel ice by truck or tracked vehicle. While the period will vary from year to year, this mode of transportation is usually possible from January 15 until May 1.

Equipment would be moved overland to cluster locations when weather conditions allowed proper construction of snow roads.

b) At Cluster Location

Rig movement at cluster locations would probably follow the North Slope practice; that is, skidding all major rig components on prefab matting, with the use of rails and/or teflon buttons to reduce friction. In this manner, an entire rig move can be accomplished in one day.

c) Season

While rig moves can be carried out under very adverse conditions and are thus generally independent of season, it is anticipated that for development drilling operators would complete rig and support-facility transportation during barging season.

Rig movement at cluster location would be carried out when required, and would be totally independent of season.

11. Manpower Requirements

Activity at a cluster location during the drilling and producing phase would vary with location and type of reservoir. For example, in deep reservoirs (9000 feet or deeper), one cluster would probably be sufficient to effectively deplete the reservoir. Shallower reservoirs would have multiple clusters with only four to six directional wells each. Drilling rigs might operate simultaneously, one for each cluster. A deviated hole to 9000 feet might require thirty to forty-five days' rig time for a cased hole, plus fifteen to twenty days for testing and completion. Larger clusters thus represent a year-long program for the drilling alone, and might justify the use of a separate completion rig. Drilling and completion procedures are specialized tasks, and separate rigs have been used in southern areas.

a) Crew Scheduling

Crew size, hours worked per day, and crew scheduling would be a matter of company policy. Personnel at the rig site would depend mainly on the length of work day, with two crews on site for twelve-hour shifts and three for eight-hour shifts.

Including supervision and ancillary services, the rig population thus varies from thirty to thirty-five people.

Use of a completion rig, following "in the tracks" of the drilling rig, would add one crew plus supervision and services--about five to ten people.

Camp facilities for thirty-five to forty-five persons require a staff of five, for a total cluster population of forty to fifty, with one drilling rig and one completion rig operating simultaneously.

b) Crew Transportation

Crew-change schedules would vary according to company preference.

However, most require one crew change per week per drilling rig. Trips between rig and staging area are minimized, because of uncertain weather conditions in the Delta and a resulting preference for exchanging crews at the well site rather than in Inuvik. This policy avoids rig shutdowns where local flights to the rig are delayed, although it involves holding over the plane from the south.

Flights between Inuvik and the south are almost daily, by commercial and/or company aircraft. Total support for the drilling and completion activity, including crew changes, would result in three to six trips per week to each drilling cluster; i.e., almost everyday, if completion activities were carried out by a separate rig at the same time. Personnel transportation would be mostly by Twin-Otter aircraft, with sporadic use of helicopters or hovercraft.

c) Accommodation

Drilling (personnel and completion, if applicable) would be housed in standard portable camp units, with two men to a room, and common units for eating, recreation, sanitation, etc. All camp facilities would be set on a gravel pad or piling, and have self-contained disposal facilities for sanitary waste and garbage; they would have the same effect (or less) on the environment as exploratory drilling camps now being used in the Delta.

12. Waste Disposal

a) Solid Waste

Waste such as garbage, scrap lumber and packaging materials would be incinerated and the remains ultimately disposed of by burial in the sump or in pad fill. (Disposal of solids from drilling operations and abandonment of sumps is discussed under "Mud Systems".) Large items, such as worn-out or damaged equipment, would be collected and transported to a central site for salvage operations.

b) Sewage

Sewage would be contained in open sumps and subsequently buried under pad fill.

c) Miscellaneous Liquid Wastes

Disposal of liquid wastes resulting from drilling and completion operations is discussed under "Mud Systems" and "Completion Operations".

13. Noise Levels

a) Drilling and Completion Operations

Noise levels from drilling and completion operations would be no greater than for current exploration activity.

b) Vehicles

Personnel and camp supplies would be transported mainly by aircraft. Typical aircraft types include Twin-Otter, Beaver, Sikorsky 58-T and Bell 212 helicopters, and Hovercraft SRN-6. In addition, large trucks would be active during rig moves and a small amount of power-boat activity would be expected on the channels during the summer. (See "Rig Movement" and Manpower Requirements".)

14. Location Restoration

All operations would be carried out either on a gravel pad deep enough (minimum 4 to 5 feet) to protect the surface organic layer and underlying permafrost, or on piles. Equipment would be either transported in winter or landed at a specially constructed docking area, connected by gravel road to the cluster pad. Consequently little location restoration would be required, beyond normal clean-up of drilling and construction debris. Such debris would be either incinerated, or buried in the sump or pad fill.

Restoration of the sump area is discussed under Mud Systems. The sequence and timing of the drilling/completion operations would dictate whether the sump would remain open for some time or be restored immediately. Seepage would be prevented by use of an impermeable membrane or something similar.

Drilling Testing

15. Drillstem and Production Testing

Conventional drillstem and production tests are carried out in the arctic. Precautions must be taken on account of the cold environment, low reservoir temperatures, and unique ecological system in the far north.

a) Drillstem Testing

At present two methods are being utilized for drillstem testing. The conventional method can be used with relatively little modification. It consists of a series of flow and shut-in periods from which the reservoir and fluid properties can be determined by using the pressure-buildup and fluid-sample data. Such reservoir and well parameters as damage ratio, permeability productivity index and absolute open-flow potential can be determined conventionally.

The second testing method, which Imperial Oil Limited now uses, is the closed-chamber drillstem test. This type of test minimizes the volumes of reservoir fluids produced to surface. It differs from the conventional drillstem test in that the well is closed in at the surface when producing, and open at the surface only when shut in at the formation. Closed-chamber testing is instrumented so that fluid influx can be monitored and flow rates determined when the test is completed. One disadvantage of the method is that it may not provide as great a depth of reservoir investigation as the conventional test.

b) Production Testing

Production testing is carried out in cased hole with tubing-bridge plug-packers, and is designed to provide more comprehensive information about the reservoir than can be obtained by a conventional drillstem test. One of the most serious problems encountered when production testing in the arctic has been the formation of gas hydrates in the tubing string. Downhole freeze-off problems in gas wells can be minimized or eliminated by:

i) Proper start-up procedures.

ii) Introducing an external source of heat to the annulus, to prevent hydrate formation.

iii) Injecting fluids to inhibit hydrate formation.

Production testing almost always requires some relatively high flow rates of hydrocarbons to obtain an adequate evaluation of well deliverability. Obviously, there are at present no large storage facilities available to contain these volumes of fluid. It would therefore have to be flared. Care would have to be taken to utilize the most efficient flaring methods, to protect the environment from permafrost degradation and emission of unburned hydrocarbons.

16. Completion Operations

It is possible that a separate rig (similar to the drilling rig but smaller) would be used for completion operations. This phase of the activities would involve mainly: 1) installing subsurface production equipment, 2) perforating and stimulating, and 3) initial production testing.

Completion-rig movement would be essentially the same as for the drilling rig. Manpower requirements at the cluster would be increased by about six to ten men per completion rig, assuming one twelve-hour tour daily. The completion activities at a cluster would probably be conducted along with the drilling operations, and most support facilities such as storage and accommodations would be common for both activities. It is expected that about fifteen to twenty days would be needed to complete and production-test these wells.

Activities, other than those mentioned, that could affect environment include the following:

a) Mud Displacement

All or part of the mud remaining in the cased hole after drilling would be displaced to a water- or oil-based packer fluid. Consideration would be given to processing the mud for re-use in other drilling activities, or disposing of it in the sump as described under "Mud Systems". As much as 1000 barrels of mud could be displaced to surface during this operation.

b) Stimulation

In the event that the wells needed acid stimulation to remove wellbore impairment caused in drilling, the acids would either be transported by truck to the clusters or mixed and blended on location. The same precautions could be taken with the acids as with other stored liquids. During initial flow from the well, part of the effluent could be spent-acid

water. It would be relatively inert and would be disposed of in the sump.

c) Production Testing

Effluents from initial well testing and cleanup operations could include: 1) spent-acid and formation water, 2) liquid hydrocarbons, and 3) gaseous hydrocarbons. Test facilities would be used to separate liquids and gas. The water volumes would range from nil to a few hundred barrels, and would be disposed of in the sump. The gas and condensate would be fully combusted, such that a minimum of partially combusted hydrocarbons is emitted to the atmosphere. A rough estimate of hydrocarbon volumes expected during an initial production test would be 200 MMSCF gas (mostly methane) and 2000 barrels of condensate.

17. Workovers and Infill Drilling

In general, little rig activity would be expected for five to six years after the initial drilling and completion program. After that time some remedial well work and infill drilling would probably be needed. The remedial workovers would resemble the completion operations (i.e., same type of movement, manpower requirements and activities). Workover frequency can be roughly estimated at one to two workovers a year for each six- to eight-well cluster, with each workover lasting fifteen to forty-five days. Additional infill drilling would probably add an additional well per year per cluster, with rig activity going to about the tenth year of operation.

TABLE I

WELL DESIGN SUMMARY
(PROBLEMS UNIQUE TO ARCTIC WELL DESIGN)

DESIGN CONSIDERATIONS	DESIGN REQUIREMENT(S)	DESIGN METHOD OR PROCEDURE	REMARKS
1. External Freezeback			
Refreezing of drilling mud and permafrost around a wellbore which generates high external pressures.	Design casing strings set through permafrost to withstand the pressures generated by external freezeback. Maximum freezeback pressure gradients measured in field test are on the order of 1.5 psi/ft.	Design surface casing strings for 1.5 psi/ft external collapse gradients. 13-3/8" N-80 or stronger grade casing is adequate for permafrost depths encountered in the Mackenzie Delta.	Two field tests at Prudhoe Bay, Alaska measured freezeback pressure gradients as high as 1.5 psi/ft at shallow depths decreasing to about .65 psi/ft at deeper depths. One test in the Mackenzie Delta measured a maximum freezeback pressure gradient of about 1.1 psi/ft.
2. Internal Freezeback			
The freezing and subsequent expansion of trapped casing to casing annular water-based fluids.	Casing to casing annuli through permafrost intervals must be filled with suitable nonfreezing fluids during periods in which a well is vulnerable to freezeback.	Incorporate into the well design a means to facilitate the placement of nonfreezing fluids in vulnerable annuli. Two acceptable ways in which this can be accomplished are shown in Figure 1: (1) a circulating device can be installed in the inner string or (2) a hanger-tieback assembly can be used so that inner string can be retrieved during suspension.	Experience with North Slope and Mackenzie Delta wells indicates that extreme care must be taken to insure that freezable drilling fluids are displaced from vulnerable annuli, and replaced with an adequate nonfreezing fluid.
3. Subsidence and Downdrag			
Thawing of permafrost causing subsidence around well, resulting in a frictional downdrag on exposed casing string.	Minimize thermal disturbance around the wellbore during producing life of the well. Based on current knowledge of the problem from field testing at Prudhoe Bay, indications are that a thaw radius of about 10' can be tolerated with no adverse effects on the well. Thermal insulation will be required to limit thaw to the $\pm 10'$ range.	1. Provide a casing design so that thermal insulation can be installed through the permafrost. For example, 13-3/8" casing will allow for adequate insulation, and provide room for 5" tubing with standard subsurface safety equipment.	1. Core analyses and shot hole evaluations indicate that the permafrost in the Mackenzie Delta is not typically ice-rich below about 50'; i.e., the ice merely occupies pore space that would otherwise be occupied by water in the thawed state. Consequently, thaw induced subsidence is predicted to be of a small magnitude and mathematical models indicate that resultant downdrag loads can be accommodated by standard casing designs.

DESIGN CONSIDERATIONS	DESIGN REQUIREMENT(S)	DESIGN METHOD OR PROCEDURE	REMARKS
Subsidence and Downdrag (Continued)			
4. Decomposition of Hydrated Gas Reservoirs	Heat input will cause decomposition of solid gas-hydrates resulting in a pressure buildup if contained or communication of the liberated gas if not contained. - Design casing strings set through gas-hydrate reservoirs to withstand collapse pressures equal to the pressure required to cause formation failure. Use 1.0 psi/ft collapse gradient when fracture gradient not known. - Provide a means to vent gas from annuli if required.	- Install at least N-80 grade casing. - Use Buttress or equivalent-strength joints.	2. Wells in areas with particularly competent permafrost may not require insulation as part of the well design.
	- Design casing strings set through gas-hydrate reservoirs to withstand collapse pressures equal to the pressure required to cause formation failure. Use 1.0 psi/ft collapse gradient when fracture gradient not known. - Provide a means to vent gas from annuli if required.	13-3/8" N-80 or stronger casing adequate for hydrate zone depths encountered in Mackenzie Delta. - Install a vented relief valve on casing-casing annuli at wellhead or install special vent strings.	Hydrate occurrences are at this time speculative; however, strong evidence exists that gas hydrates are present at some locations in the Mackenzie Delta.

TABLE II

WELL DESIGN SUMMARY

(PROBLEMS NOT UNIQUE TO ARCTIC WELL DESIGN)

DESIGN OR OPERATIONS CONSIDERATION	REQUIREMENTS	METHOD(S) OR PROCEDURE(S)	REMARKS
1. Hydrate control during well startup.	Do not flow wells for extended periods when stable hydrate conditions exist at either the sandface or in the tubing string.	1. Control pressure drawdown across sandface in order to minimize the temperature drop in the formation while flowing the well at the highest practical rate to insure a rapid heat-up of the well tubulars and surroundings.	There must be a compromise in minimizing drawdown and maximizing rate. The optimum flow conditions (or range of conditions) can be determined by wellbore thermal simulators. If the thermal analysis indicates that the well cannot be heated out of the hydrate stability range in a relatively short time, hydrate-control systems (alcohol-injection heat systems) will be installed.
2. Sand Control	Wells should have the capability to flow at maximum practical rates without an appreciable amount of sand production.	2. During startup, inhibit hydrate formation with alcohol or heat addition, if necessary.	Current evaluation programs are aimed at determining sand-control requirements prior to development activities.
3. Production Parameters	Tubulars and wellhead equipment to be designed to withstand the most extreme conditions imposed by the reservoir environment and ambient conditions.	If sand control is required, conventional sand-control techniques used in other areas (gravel pack, plastic consolidation, other chemical consolidation) will be employed. Tubing and production casing to be designed to 1. Withstand maximum pressures that will be imposed, both burst and collapse, with standard safety factors included. 2. Withstand the maximum stresses that will be imposed as a combined result of pressure, temperature, axial loading and buckling. Wellheads will be of a standard design with the material having been tested to conform to low-temperature requirements. Wellheads will conform to API Specification 6A.	In general, it is anticipated that well equipment used in other parts of the world will be suitable for Mackenzie Delta wells, with the exception that the materials will conform to special low-temperature requirements (Charpy impact toughness) to prevent damage in handling and servicing during extremely cold conditions.

DESIGN OR OPERATIONS CONSIDERATION

REQUIREMENTS

METHOD(S) OR PROCEDURE(S)

REMARKS

4. Corrosion Control	Minimize corrosion rates to within acceptable limits for all well components.	1. Use inhibitors or selective metal-lurgy to attain acceptable corrosion rates. 2. Establish effective inspections and preventative maintenance programs.	No unique corrosion problems are expected to be posed by arctic conditions.
5. Safety Systems	Provide both surface and subsurface safety systems that will automatically shut in a well in the event of an emergency condition.	Install remote-controlled surface and subsurface safety valves. The valves will be of the "fail safe" type and will automatically shut in a well for specified emergency conditions. In addition, the safety-valve systems will have remote and manual shut-in capabilities.	1. The objective of the safety system is to protect personnel from injury, equipment from loss or damage and to protect the environment. 2. The subsurface safety valve will be set below the base of the permafrost.
6. Monitoring	1. Provide a means to continuously monitor well-safety systems. 2. Provide a means to monitor well parameters; i.e., flow rate, wellhead pressure/temperature, annuli pressures, etc.	1. A computerized production control system will link all components of the production system and provide all necessary monitoring capability from a central location. 2. Wells will be monitored by lease operators in a periodic conventional manner.	The monitoring signals can include system status, alarm conditions, measurement and control functions and will be available continuously or on request.
7. Contingency Operations	Provide equipment, personnel training and detailed plans/guidelines to cope with any emergency situation.	1. Provide the most up-to-date well-control equipment when drilling the wells. Train drilling crew thoroughly in well-control procedures. 2. Provide surface and subsurface safety valves to shut in production wells in the event of emergency conditions; i.e., flowline break, process failure, fire, etc. 3. In the event of a failure of all well-safety systems, initiate contingency plans to bring a well under control; i.e., kill systems/methods, relief wells, etc.	The probability of a blowout in a Mackenzie Delta development well is extremely remote. Formation conditions will be known from exploration and delineation wells and the most up-to-date safety equipment and well-control procedures will be employed at all times.
8. Disposal and Observation Wells	Same basic design requirements as for production wells.	Basically, the same methods/procedures as for the production wells. However, the quantities of liquids to be injected are such that mechanically both streams (water and condensate) could be injected into one well with a dual-completion arrangement.	1. Observation wells might be required in some fields to monitor reservoir performance. 2. Injection wells will be required to dispose of water and to inject liquid hydrocarbons back into producing formations.

TABLE III

ARCTIC COMPLETION FLUIDS

FLUID CATEGORY	SPECIFIC FLUID DESCRIPTION	DENSITY (LB/GAL)	FREEZING POINT (°F)	GENERAL COMMENTS
Brine Solutions	1. KCl solution	9.45	12.8	1. Freezing points are the crystallization temperatures of the eutectic compositions. Densities given are for the eutectic compositions.
	2. NaCl solution	9.81	- 6.0	
	3. CaCl ₂ solution	10.75	-59.8	
	4. NaCl/KCl solution		- 9.5	
Salt Muds	1. Polymer, Bentonite, KCl system	8.4+	12.5	1. Freezing points of aqueous phases of mud approximately the same as pure brine solutions of the same concentration.
	2. Polymer, Bentonite, NaCl system		-10.0	2. Mud systems such as described have been relatively successful in drilling through permafrost.
	3. Polymer, Bentonite, NaCl/KCl system		- 9.5	
	1. Polymer, Bentonite, 10 lb/bbl KCl, 25% glycol	8.4+	7.0	1. Same comments apply as made for salt muds except freezing points given are defined as the point at which fluids are non-pumpable. This temperature is 3-5°F colder than crystallization point for same fluid.
Alcohol Solutions	2. Polymer, Bentonite, 40 lb/bbl KCl, 25% glycol by weight		-13.0	
	1. Ethylene glycol a) 20% glycol by weight b) 50% glycol by weight	8.57	16	1. Several other glycols available which give higher freezing points.
		9.0	-32	2. Density given at 32°F.
	1. Diesel Oil	7.0		1. Diesel has been used in observation wells in the Delta with no adverse effects to date.
				2. Gelled diesel provides good thermal insulation properties.

TABLE IV

EMERGENCY REPORT FORM

WELL NAME: _____ RIG NO.: _____

FIELD: _____ DEPTH: _____

DATE OF EMERGENCY: _____ TIME: _____

WEATHER:

WINDSPEED: _____ MPH DIRECTION: _____

TEMPERATURE: _____ °F VISIBILITY: _____

CLEAR: _____ CLOUDY: _____ FOG: _____ SNOW: _____

LAST CASING SIZE: _____ DEPTH: _____

B.O.P. STACK 1. _____ RATING: _____ PSI

2. _____ RATING: _____ PSI

3. _____ RATING: _____ PSI

4. _____ RATING: _____ PSI

IS B.O.P. STACK OPERATIVE? _____

SUMMARY OF EMERGENCY: _____

PRESENT WELL STATUS: _____

CAN WELL BE SHUT IN? _____

DRILL PIPE PRESSURE: _____ PSI CASING PRESSURE: _____ PSI

CALCULATED BHP: _____ PSI

PROPOSED CONTROL PROCEDURES: _____

PLANS FOR CONTAINING WELL FLUIDS: _____

PRESENT ACTIVITY AND PLANS: _____

INJURIES: _____

EVACUATION PLANS: _____

FIGURE 1

MACKENZIE DELTA CONCEPTUAL WELL DESIGN

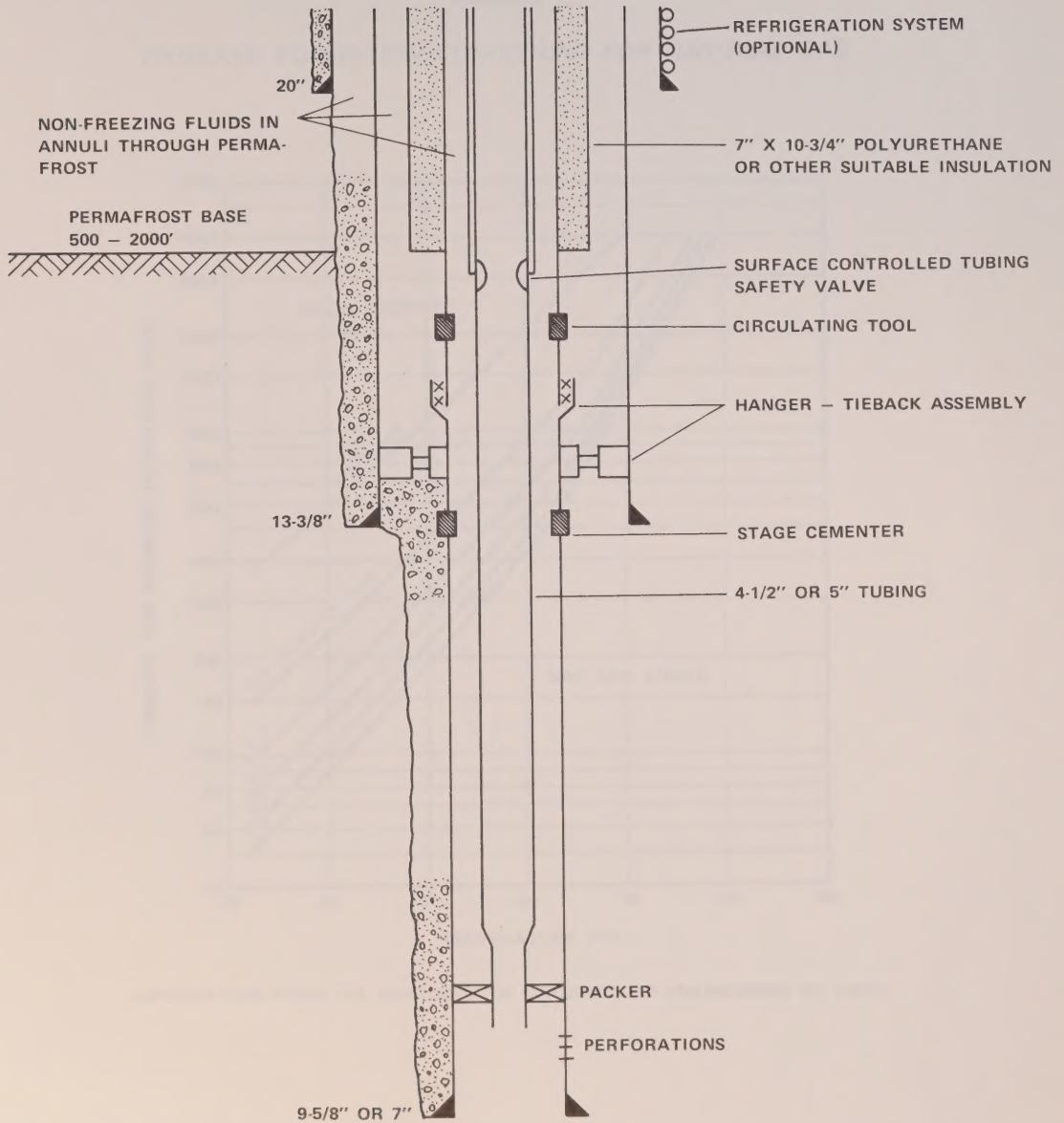
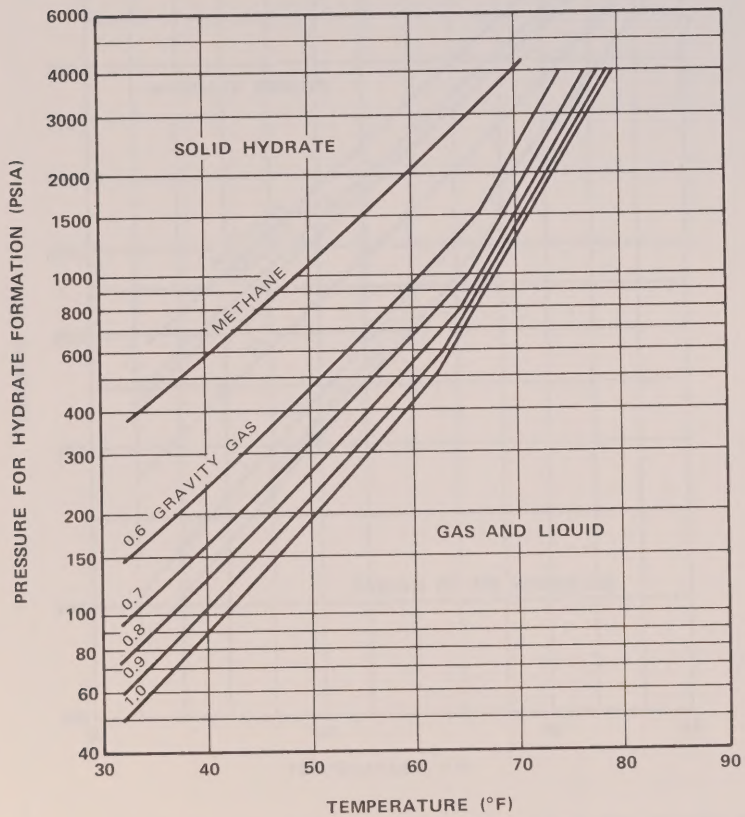


FIGURE 2

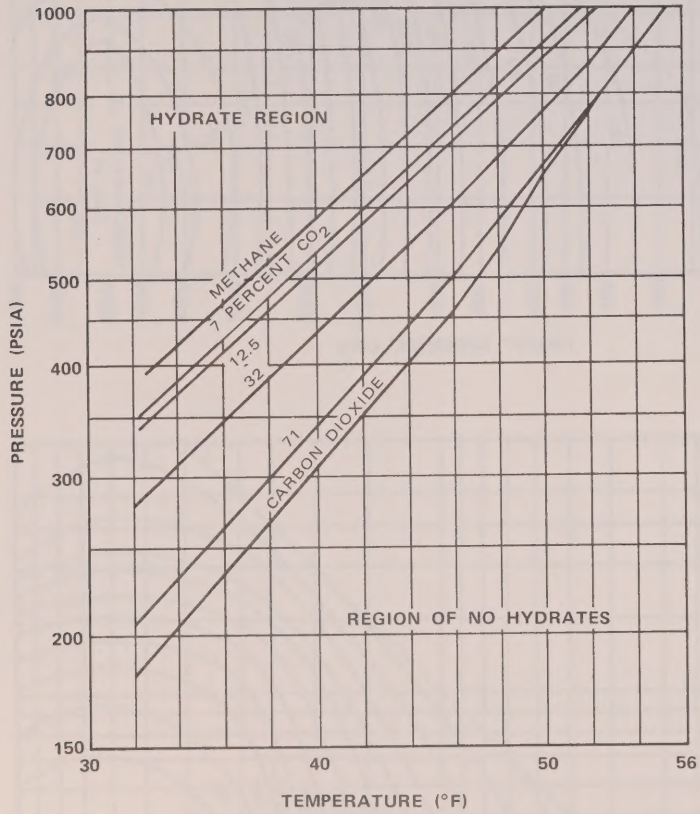
HYDRATE FORMATION CONDITIONS FOR NATURAL GAS



INFORMATION FROM THE HANDBOOK OF NATURAL GAS ENGINEERING BY KATZ

FIGURE 3

HYDRATE FORMATION CONDITIONS FOR CARBON DIOXIDE METHANE MIXTURES



INFORMATION FROM THE HANDBOOK OF NATURAL GAS ENGINEERING BY KATZ

FIGURE 4

PERMISSIBLE EXPANSION OF NATURAL GAS WITHOUT HYDRATE FORMATION

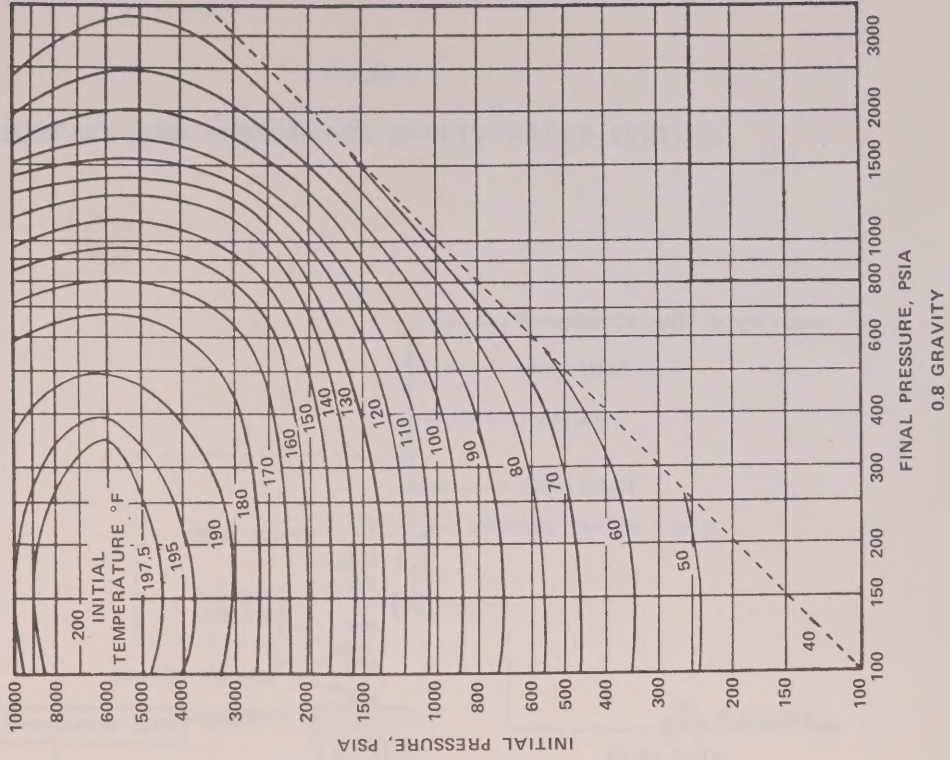
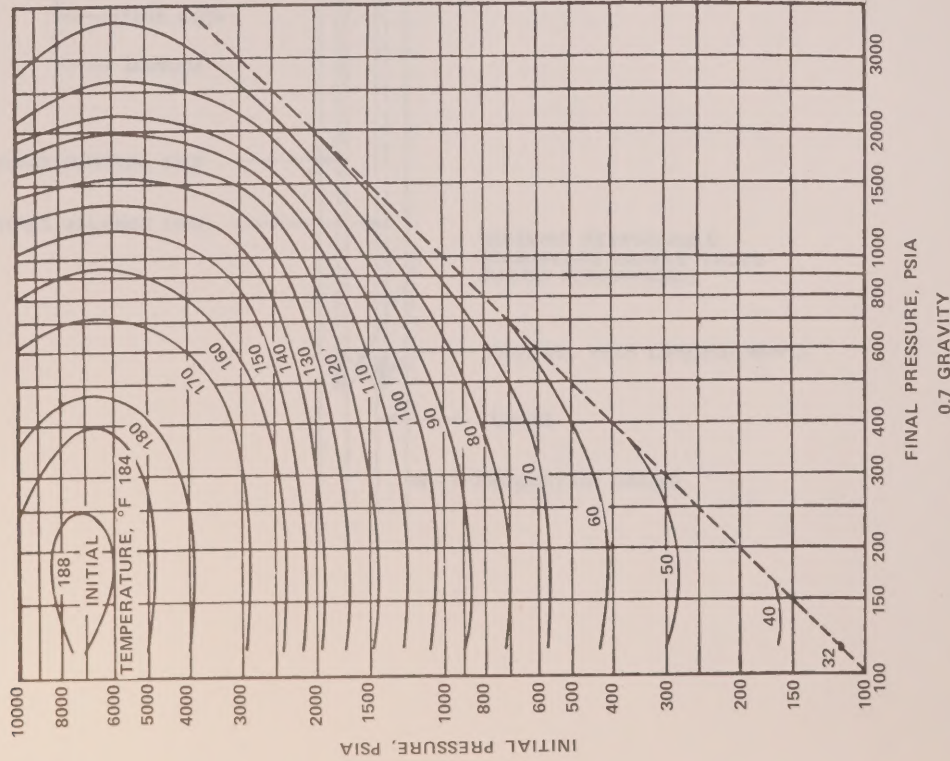


FIGURE 5

SURFACE AND SUBSURFACE SAFETY VALVE SYSTEMS

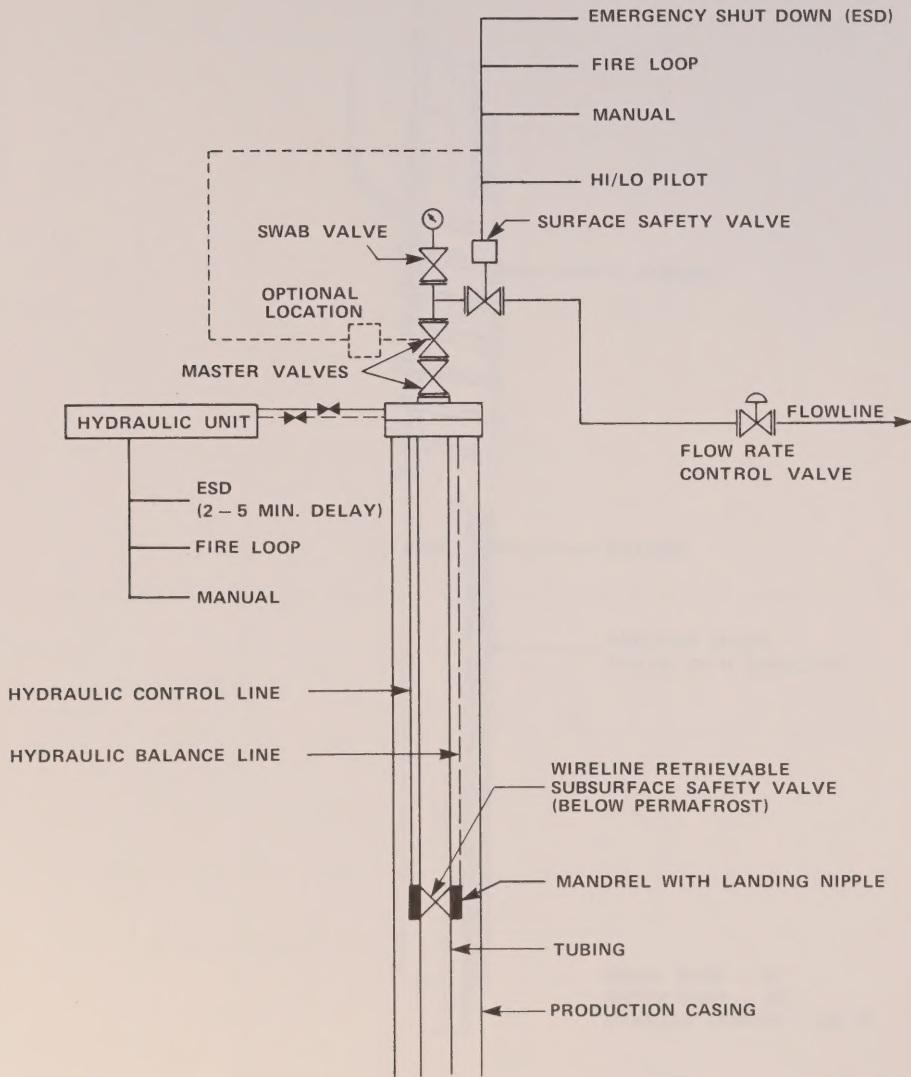


FIGURE 6

REFRIGERATED CONDUCTOR PIPE

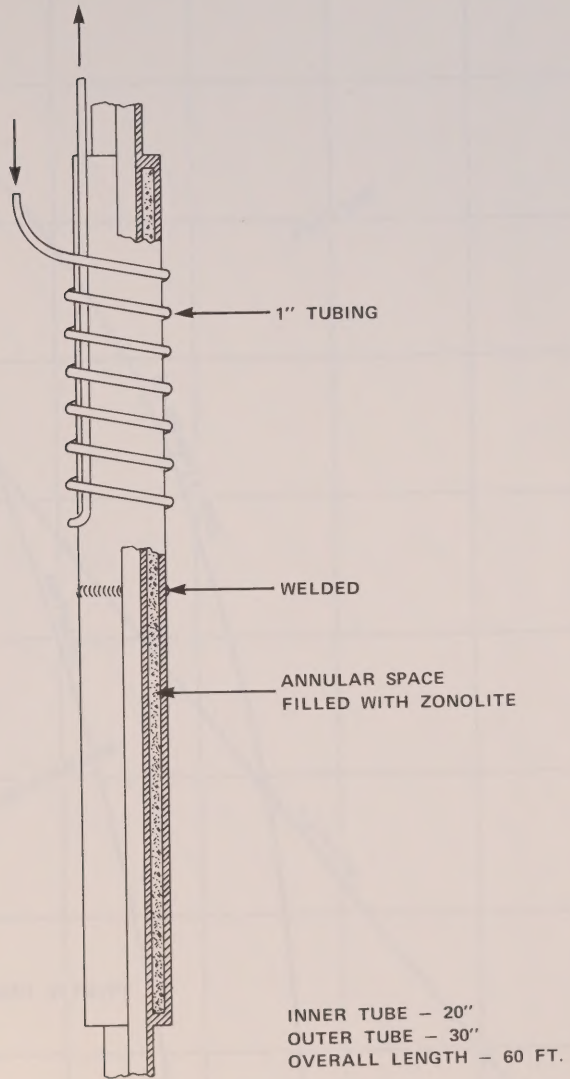


FIGURE 7

HYDRATE LAYER THICKNESS

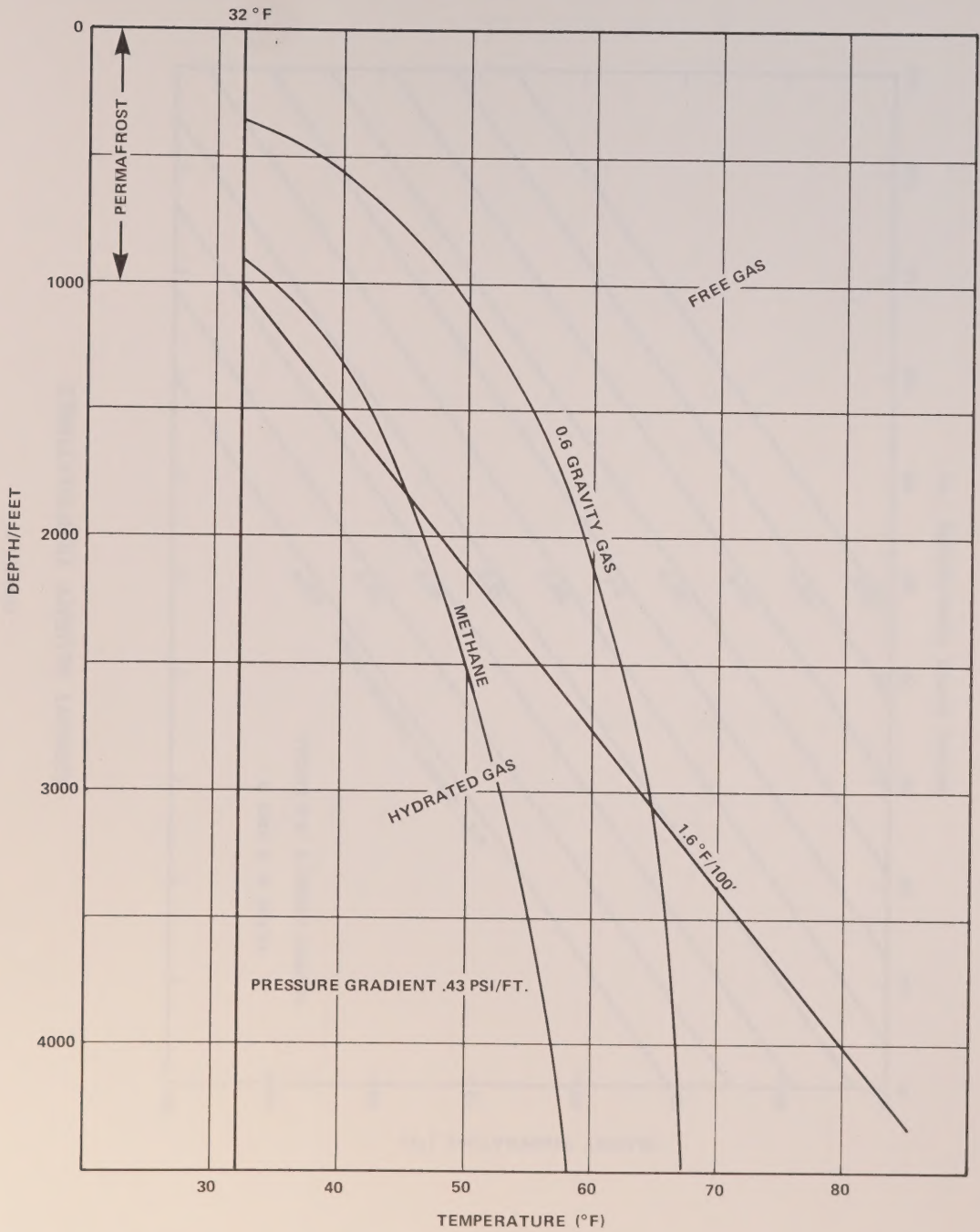


FIGURE 8

CEMENT SLURRY TEMPERATURES

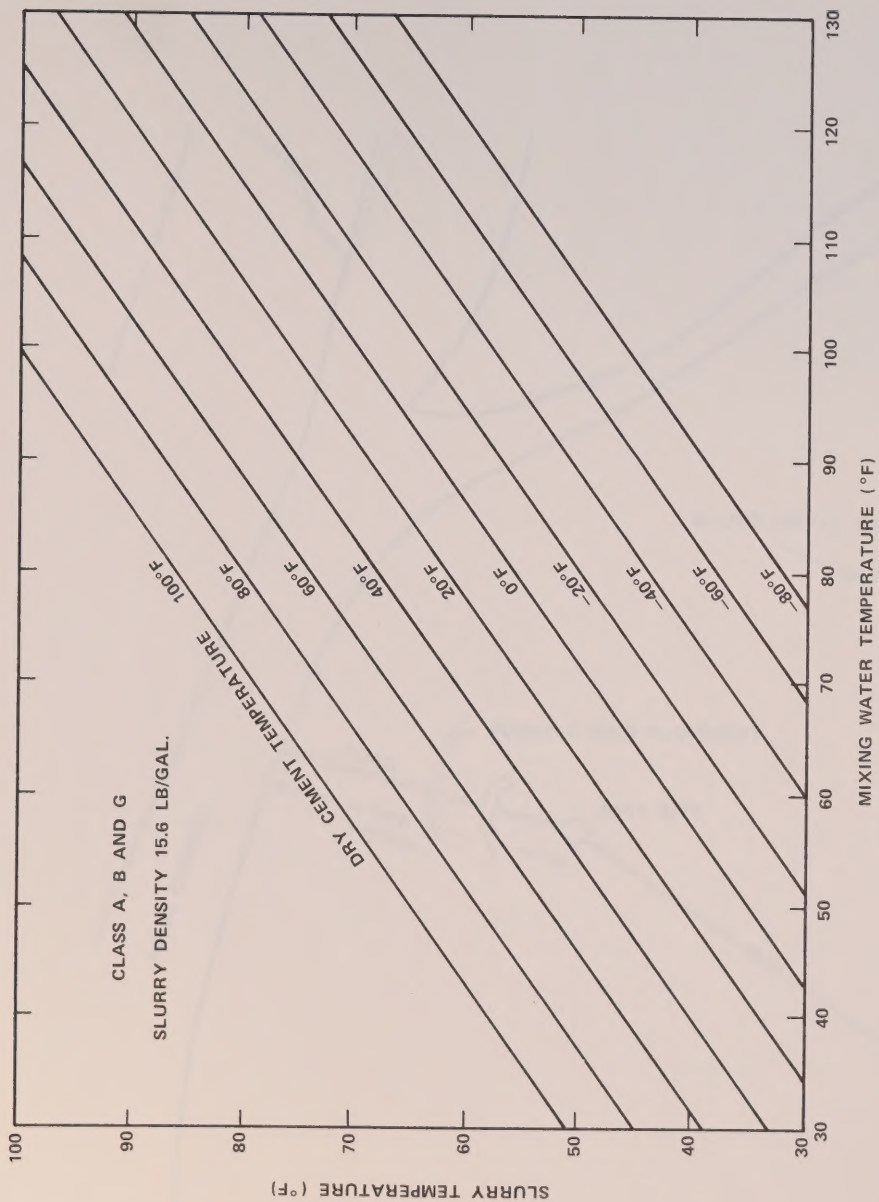


FIGURE 9

WELL SITE SAFETY PLAN

